STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	)	
	)	**Docket No. 12-0511**
Proposed General Rate Increase for Gas Distribution Rates	)	
	)	
Peoples Gas Light and Coke Company	)	
	)	**Docket No. 12-0512 (cons.)**
Proposed General Rate Increase for Gas Distribution Rates	)	

SUMMARY OF POSITION
OF THE PEOPLE OF THE STATE OF ILLINOIS

The People of the State of Illinois

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TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

I. INTRODUCTION/STATEMENT OF THE CASE

The People of the State of Illinois ("the People" or "the AG"), by Lisa Madigan, Attorney General of the State of Illinois, and pursuant to the request of the Administrative Law Judges, hereby file their Summary of Position in the above-captioned docket, consistent with the Initial and Reply Briefs filed by the Attorney General's Office on March 8, 2013 and March 26, 2013, respectively. (*See* AG Initial and Reply briefs for the People's Introduction and overall summary of the case.)

II. TEST YEAR (Uncontested)

III. REVENUE REQUIREMENT

The AG argues that the overall revenue increase *should not exceed* $15.4 million for Peoples Gas Light & Coke Company ("PGL") and $2.6 million for North Shore Gas Company ("NS"). The adjustments proposed by the People should be viewed as cumulative with the work and recommendations of Commission Staff and other intervenors' witnesses.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

2. Peoples Gas

B. Potentially Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Cushion Gas Calculation

2. Plant

a. Forecasted Test Year Capital Additions – Utility Plant in Service (PGL)

b. Advanced Metering Infrastructure Project

c. LNG Control System Upgrade and Related Project (PGL)

d. Calumet System Upgrade (PGL)

e. CNG Fueling Station (PGL)

f. Incentive Compensation – capitalized amounts disallowed in prior cases

g. Original Cost Determination as to Plant Balances as of December 31, 2011

3. Budget Plan Balances

4. Accumulated Deferred Income Taxes - 50/50 Sharing Related to Tax Accounting Method Change

C. Potentially Contested Issues

1. Year End Rate Base or Average Rate Base

As noted by AG witness Michael Brosch[1], the Companies' proposed test year employs forecasted 2013 rate base, capital structure and operating income amounts.

[1] Mr. Brosch is a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to regulatory projects for utility regulation clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses, utility reorganization analyses and focused investigations related to utility operations and ratemaking issues. Mr. Brosch has testified before utility regulatory agencies in

However, the Companies' filings are not internally consistent because they include both average and year-end information in a manner that distorts and overstates the asserted revenue requirement. The Companies' proposed rate base is forecasted at year-end as of December 31, 2013, while the balance of the test year revenue requirement calculations, including revenues, O&M expenses and cost of debt, utilizes forecasted average data expected to be experienced throughout calendar year 2013. AG Ex. 1.0 at 6.

The Companies have proposed the use of a hybrid test year approach, using forecasted operating revenues and operations and maintenance ("O&M") expenses throughout the 2013 test year that have not been annualized at year-end, while proposing a year-end rate base including net plant investment that is forecasted to exist at year-end. This approach significantly increases the test year 2013 revenue requirement, while destroying the balance that is normally required in test year regulation, where all elements of rate base and operating income are matched and made to be internally consistent.

Both AG witnessess Brosch and David Effron[2] recommend that an average rate base be employed in setting the Companies' rates, so as to match the average income statement and cost of capital calculations that are employed while not overstating the revenue requirement expected to be incurred in the 2013 test year. Staff witness Daniel Kahle and CUB witness Ralph Smith likewise endorsed the use of an average rate base methodology to ensure that the Companies' revenues match its actual costs.

The Companies attempt to justify their proposed hybrid test year approach using year-end rate base in an otherwise average test year by citing "several reasons" for this approach:

> 1. The rates being set in this proceeding will not go into effect until well into the test year, most likely not until sometime in July 2013 and will likely be in effect until sometime in 2015.

Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, New Mexico, Ohio, Oklahoma, Texas, Utah, Washington, and Wisconsin in regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. AG Exhibit No. 1.1 is a summary of his education and professional qualifications. A listing of Mr. Brosch's previous testimonies in utility regulatory proceedings is set forth in AG Exhibit No. 1.2. In Illinois, Mr. Brosch has testified in several major proceedings before the ICC. These include Peoples Gas rate cases in Docket Nos. 90-0007 and 07-0241, North Shore Gas Company Docket No. 92-0242, Illinois Bell Telephone Company in Docket Nos. 92-0448 and 92-0239, ComEd rate case Docket Nos. 07-0566 and 10-0467 and Ameren Illinois Utilities Docket Nos. 07-0585 through 07-0590. Mr. Brosch also testified in ComEd Docket No. 09-0263 involving the Advanced Metering Infrastructure Pilot Program and Associated Tariffs, in response to ComEd's alternative regulation proposal that was filed in Docket No. 10-0527, and in the initial and second year formula rate case proceedings involving ComEd and Ameren Illinois, Docket Nos. 11-0721, 12-0321, 12-0001 and 12-0293, respectively.

[2] Mr. Effron is a Certified Public Accountant and consultant specializing in utility regulation. His professional career includes over twenty-five years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. He has analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses he prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies. He has testified in numerous cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington. He received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State. He has a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University. AG Ex. 2.0 at 1-2.

> 2. The Companies are permitted under the Commission's rules to use a year-end rate base.
>
> 3. The Companies have been and continue to increase their investment in plant in service to better serve their customers.

PGL Ex. 7.0 at 4 (Hengtgen); NS Ex. 7.0 at 4. Aside from these arguments, the Companies' only quantitative analysis is offered in support of the third argument, where in PGL/NSG Exhibits 7.2, historical balances of "Gross and Net Plant" are summarized to show how such amounts have changed historically.

The reasons offered by the Companies for the unorthodox proposal to incorporate year-end rate base values in a future test year are hardly persuasive. First, an assumed effective date of new gas rates from these proceedings in mid-2013 does *not* support adoption of year-end rate base. Between rate case orders, all the elements of the revenue requirement are subject to change and can be expected to change. It is impossible to accurately predict how the timing of new rates becoming effective will impact a utility's earnings. If future revenue or cost variances from the test year 2013 amounts that are used to set rates are favorable, the Company's earnings are likely to exceed authorized levels. Conversely, if such financial variances are negative, earned returns may be lower than authorized levels. When a future test year is employed to set rates, the potential for earnings attrition is minimized because the forecasted financial data upon which rates are based is not dated. Stated differently, there is minimal regulatory lag when a future/forecasted test year is employed. AG Ex. 1.0 at 11-12. Under these circumstances, it is not reasonable to select only one element of the ratemaking equation, in this case the rate base amounts, and presume such amounts should be mismatched to the rest of the test year just in order to ensure that revenue requirements and potential future earnings are maximized.

Second, neither the Companies nor Mr. Hentgen provided any quantification of either historical or projected earnings attrition to justify mismatching the forecasted test year by using average income statement and cost of capital amounts with year-end rate base. In response to Data Requests DGK 7.06 and DGK 7.07, North Shore and PGL admitted that the only analysis performed in support of using the year-end versus average rate base position was presented in its direct filing in this case by Mr. Hentgen in comparing historical levels of Gross and Net Plant in Service. AG Ex. 1.0 at 12.

Likewise, historical trends in "Gross and Net Plant" quantified in PGL and NS Exhibits 7.2 do not reveal either historical earnings attrition or future expected earnings attrition that might justify using a year-end rate base. As noted by Mr. Brosch, the utilities' total revenue requirement is driven by more than just changes in Gross Plant in Service and Accumulated Depreciation. Operating income is a function of sales and revenue levels and each category of labor and non-labor expense. Rate base investment levels are driven by changes in Net Plant in Service as well as changes in Accumulated Deferred Income Taxes ("ADIT"), gas in storage and other working capital elements. In the present economic environment, declining interest rates have created a setting in which long term debt can be refinanced to yield significant savings that reduce revenue requirements. Mr. Hentgen's single-issue analysis focused on historical changes in Gross and Net Plant in Service does not address the multitude of other issues that impact revenue requirements. It is therefore essential that a proper matching of the elements of the revenue requirement be maintained to ensure that just and reasonable rates are approved by the Commission.

AG witness Effron concurred with these observations. First, he noted that it is unorthodox to use a year end rate base in conjunction with a future test year. Mr. Effron testified that it has been the consistent practice to use an average rate base when a future test year has been used to determine a regulated utility company's revenue requirements. For example, in each of the Companies' two most recent rate cases, (Docket Nos. 09-0166 and 11-0280 for North Shore and Docket Nos. 09-0167 and 11-0281 for PGL) a future test year was used to determine the revenue requirements, and in all cases, the future test year rate base was an average rate base. The same is true for the most recent cases filed by Ameren Illinois Company (Docket Nos. 11-0279 and 11-0282), and Nicor Gas Company (Docket No. 08-0363).

He noted that there are significant reasons why it is the usual practice to use an average rate base in conjunction with a future test year. First, the average rate base measures the net investment in facilities to provide utility service over the course of the year, rather than as of a point in time as of the end of the year. It is internally consistent with the measurement of expenses, billing determinants, and income over the course of the year. That is, using an average rate base properly matches the calculation of rate base with the other elements of the Company's revenue requirement and income in a given year. The return on rate base is a component of the total revenue requirement, just as expenses such as salaries and wages, depreciation, and property taxes are. This component of the total revenue requirement, the return requirement, is calculated by multiplying the Company's cost rate of capital by its rate base. This converts the cost rate into a dollar cost, just as depreciation expense is calculated by multiplying the applicable depreciation rate by the relevant depreciable plant. AG Ex. 2.0 at 5-6.

When a unit of plant is put into service in December of a given year, the Company does not incur a capital cost on that plant for the whole year any more than it incurs depreciation expense on that plant for the whole year or any more than it incurs a year of payroll expense for an employee hired in December. The Company's annual revenue requirement does not include a full year of capital cost on plant that is put into service at the end of the year. The issue of how to correctly recognize the value of the rate base when assessing a utility's capital costs has been closely analyzed by the Commission in no less than four recent cases: ICC Docket Nos. 11-0721, 12-0321, 12-0001 and12-0293. As the Commission noted in Docket No. 11-0721, using a utility company's "rate base as of December 31st of any year assumes that its investment in plant is the same on January 1st (and thereafter) of that year as it is on December 31st of that year. That clearly cannot be the case." Order, May 29, 2012, at 19.

The use of the average rate base to calculate the return requirement included in the revenue requirement is similar to calculating the return requirement for the year by calculating the return requirement for each of the twelve months and then summing those monthly return requirements. The return on the average rate base represents the actual dollar cost of capital incurred by the Company over the course of the year, and that is what is included in the Company's total revenue requirement. AG Ex. 2.0 at 6-7. It should be noted, too, that NS-PGL witness Schott confirmed during cross-examination that the Companies calculation test year depreciation expense for both companies using an averaging methodology – not an end of year basis. Tr. at 403-404.

The rate base is sometimes calculated as of the end of the test year (except for those elements of rate base that fluctuate or are seasonal in nature, such as storage gas inventory) when a historic test year is used to determine a utility company's revenue requirement. Generally speaking, a historic test year is a period consisting of twelve months of actual data, with that twelve month period ending at a point in time before the record in the rate case being processed closes. The theory supporting the use of an end of test year rate base in these circumstances is that the rate base as of the end of the test year is more representative of the investment that the utility will have in its rate base at the time that the rates being set go into effect. AG Ex. 2.0 at 7.

The circumstances present in a historical test year environment that point to the use of an end of year rate base, however, are not present in this case. The Companies have selected to use a future test year, not a historic test year, to develop their revenue requirements. Consistent with the use of a future test year, the rate bases should reflect average balances, not end of year balances, for the major components. *Id.* at 7-8.

Mr. Effron calculated the AG-proposed adjustment to the Companies' rate bases to reflect an average rate base and updated the figures in his rebuttal testimony. The effect is to reduce the North Shore test year rate base by $5,353,000 (AG Ex. 5.1, Schedule DJE-1N) and the PGL rate base by $98,886,000 (AG Ex. 5.1, Schedule DJE-1P). They should be adopted by the Commission.

In their rebuttal and surrebuttal testimony, the Companies offer various arguments in support of their unorthodox request to calculate a future test year rate base using end of year values. NS-PGL witness James Schott's rebuttal testimony characterizes use of the average rate base by Staff and intervenor witnesses as substantial "reductions in the Utilities' recovery of the costs of plant investments." He states that Mr. Effron's proposal to use an average test year rate base, rather than an end-of-test year rate base, reduces the Peoples Gas rate base by $151,958,000 and the North Shore rate base by $11,083,000. NS-PGL Ex. 22.0 at 5. But this criticism is an invalid one.

The adjustments in Mr. Effron's direct testimony to reflect an average rate reduced the Peoples Gas rate base by $86,798,000 and the North Shore rate base by $5,974,000. The numbers initially cited by Mr. Schott are reductions to estimated test year plant, not rate base. He later acknowledged in his Surrebuttal testimony that those fingures failed to recognize that the reductions to the plant balances are partially offset by reductions to accumulated depreciation and accumulated deferred income taxes ("ADIT"). NS-PGL Ex. 37.0 at 8.

Both Mr. Schott and Mr. Hengtgen attempt to justify the use of a year end rate base in this case on the grounds that the rates will not go into effect until July 2013, although the future test year begins in January 2013. But the Commission previously addressed whether the use of a year end rate base would be appropriate in similar circumstances. In his direct testimony, Staff Witness Kahle noted that in Docket No. 04-0779, Northern Illinois Gas Company ("Nicor") proposed a future test year with a year-end rate base, but that the Commission rejected this approach, finding that an average rate base "better matches the level of rate base during the test year with the revenues and expenses during the test year." Staff Exhibit 2.0, at 7-8. Nicor filed that case in November 2004, with a future test year consisting of the twelve months ending December 31, 2005 and the rates set to go into effect in October 2005. In other words, in Docket No. 04-0779, the new rates did not go into effect until approximately ten months after the beginning of the future test year. Yet the Commission found that an average rate base was appropriate (while use of a year-end rate was not) in those circumstances. If the use of an average rate base was appropriate in Docket No. 04-0779, it is certainly appropriate in the present case. AG Ex. 5.0 at 2-3.

Contrary to the Companies' claims, the use of an average rate base methodology in no way denies the Utilities recovery of a substantial part of their 2013 costs. An average rate base affords a reasonable opportunity for the Companies to recover the overall costs incurred to provide service. An average rate base, when used with a forecasted or future test year, properly matches the level of investment throughout the year with the related levels of sales, revenues, operating expenses, depreciation expenses, taxes and cost of capital that have been measured on an average, rather than year-end, basis of accounting. For example, the Utilities' cost of debt capital is expected to decline at the dates of each scheduled long term debt refinancing, but both PGL and NSG have calculated and used an average cost of debt throughout the test year, rather than annualizing the lower long term debt costs expected to exist at year-end. AG Ex. 4.0 at 6-7.

It is fundamentally unfair to ratepayers for the Companies to recover a higher cost of long term debt using average test year costs and then assert an entitlement to year-end rate base investment levels that are expected to be higher than average levels. As explained in Mr. Brosch's Direct testimony, it is important to maintain a matched and internally consistent methodology in calculating test year revenue requirement to avoid distorting and overstating the revenue requirement.

Mr. Schott's assertion that approval of an average rate base approach would "reduce dramatically the Utilities' investments allowed in rate base, especially Peoples Gas' Accelerated Main Replacement Program ("AMRP") projects" is particularly misguided. NS-PGL Ex. 22.0 at 6. As explained by Mr. Brosch, there is no disallowance of any actual investments caused by utilization of an average rate base. Mr. Schott has identified no actual investments that have actually been made by the Utilities and that are excluded from rate base under the AG's proposals. He confirmed, too, during cross-examination that is it the Company's position that it is *not* Peoples Gas' position that it could not afford to continue investing in its AMRP if the Commission uses an average rate base in the Company's rate cases. Tr. at 415.

What is "reduced" in the AG's filing is the Companies' intended overstatement of rate base that is caused by projecting plant additions further into the future than the balance of the other operating income and capital structure inputs to the test year revenue requirement calculation. Separate adjustments to PGL's rate base associated with PGL's projected CWIP amounts proposed by Mr. Effron are unrelated to the need for the Commission to calculate the Companies' rate base using average plant figures, rather than year-end amounts. AG Ex. 4.0 at 7.

Moreover, the ability to employ a forecasted test year offers the considerable advantage to the Utilities of being able to include in their rates estimated costs for planned new investments that represent costs not yet incurred. Thus, the average versus year-end rate base dispute involves no actual costs that have been incurred by the Utilities', but instead involves only a question of how far into the future we include speculative estimates of future investments that have only been budgeted by the Utilities. In contrast, if an historical rate base were employed, ratepayers would be assured of paying a return on only actual, incurred levels of plant investment, rather than uncertain estimates of future investments that are only planned to be made. In this sense, use of an average rate base reduces the risk to ratepayers of overstating the estimates of future investments that are expected to be made in the forecasted test year. The bottom line is that utilization of forecasted levels of rate base and expenses results in minimal regulatory lag to the considerable advantage of utility investors. AG Ex. 4.0 at 7-8.

The Companies' claim that they will be denied an opportunity to earn a return on all of their prudently invested capital that is used to construct new utility plant under the AG's proposed continuation of average rate base methodologies is particularly specious. The continuous capital spending incurred by the Companies is common throughout the gas utility industry and results in the continuous addition of new utility plant assets that are long-lived. New plant assets that are acquired or constructed by the Utilities will be includable in rate base for decades into the future. When PGL and NSG add new plant investments that cumulatively exceed the estimated average investment amounts included in rate base by the AG, the Companies will retain the opportunity and can be expected to seek rate base inclusion for all such incremental investments in many future rate cases during the decades that new plant remains in service. There is no permanent loss of return on investment in new plant because all new investments in long-lived plant assets are recorded on the Utilities' books and can be included in rate base within all future test years while the plant remains in service. *Id.* at 8-9.

Likewise, there is no disallowance of plant investment when new plant is added between test years, or in this case, when new plant is forecasted to be added that eventually exceeds the calculated average of forecasted test year investment levels. Ratemaking need not continuously capture growth in rate base to produce a reasonable opportunity to earn a fair return on investment. It is essential to maintain a balanced approach that quantifies all elements of the revenue requirement in an internally consistent manner. It's important to note that the AG-proposed adjustment to utilize the average rate base approach that was used in this and in previous PGL/NSG rate cases is a measurement convention, rather than any disallowance of new rate base investments. The Companies' estimated plant investments that are expected to be in service throughout the 2013 test year have been measured at an average level, based upon estimated costs without disallowances, so as to properly match the rate base with the corresponding measurement period for operating revenues, operating expenses and the estimated cost of capital – nothing more, nothing less.

Mr. Schott also argues that if the new rates in this case go into effect in July 2013, use of an average rate base deny would deny recovery of higher rate base investments that may exist by year-end 2013. NS-PGL Ex. 22.0 at 8. Mr. Schott is wrong. If new rates are effective in July, based upon an average rate base for 2013, the Company will immediately commence recovery of a return on investment for the amounts of estimated rate base investments that are in place at that date, since July is near the mid-point of calendar year 2013. This is entirely appropriate because the test year estimated expense and revenue levels at this mid-point of the calendar year should also be reasonably synchronized with the newly implemented rates. The fallacy with Mr. Schott's argument is the supposition that use of a forecasted test year somehow entitles the Companies to an expectation of zero regulatory lag throughout and after the 2013 test year. AG Ex. 4.0 at 9-10.

On the other hand, assuming new rates go into effect until July 2013, utilization of a year-end rate base, as proposed by the Companies, would produce a windfall for the Companies. Using a forecasted year-end rate base would cause the new rates effective in July of 2013 to be overstated, because such rates would include a return on forecasted rate base plant assets that do not yet exist at that time. In particular, the forecasted plant investments expected by the Companies to be added in the last half of 2013 that exceed average projected rate base levels, would represent non-existent Plant as of July that are not being used in the provision of public utility services as of July of 2013. AG Ex. 4.0 at 10.

Mr. Schott also complains that the rates being set will not reflect higher levels of investment after 2013. NS-PGL Ex. 22.0 at 9-10. But this criticism is an equally invalid one. All of the elements of the Companies' revenue requirement are dynamic throughout the passage of time. After 2013, it is reasonable to assume that PGL's gross investment level in new plant will continue to grow, as emphasized by Mr. Schott. However, after 2013, the Companies' continuing accruals of depreciation expense will produce higher accumulated depreciation reserve balances that reduce rate base. After 2013, the full annual impact of long term debt refinancing activities will be recorded as reduced interest expense. After 2013, continuing changes in gas sales volumes, employee staffing levels, wage rates, revised actuarially determined pension expenses, expense savings from new technologies or efficiency gains would all impact the Companies' revenue requirements. Bonus tax depreciation has now been extended through 2013 and will contribute to rapidly growing accumulated deferred income tax balances that reduce rate base. Finally, some of the investments in new plant for the PGL Accelerated Main Replacement Program are expected to produce significant expense savings that should be captured in future rate case test years, but are not reflected in 2013 test year expenses. AG Ex. 4.0 at 11. Mr. Schott's criticism ignores all of these facts.

As for the claim that AMRP investment will be negatively impacted, the Companies have offered no evidence that use of a forecasted test year with an average rate base will cause any deterioration in credit ratings or reduce the Companies' access to capital on reasonable terms. Mr. Schott's testimony instead indicates a "reduced willingness" to invest. In response to Data Request AG 16.01a, PGL stated, "Mr. Schott's testimony speaks for itself. That being said, Mr. Schott's testimony indicates a reduced willingness by management to invest in accelerated main replacement in the circumstances of the reductions in recovery of the costs of such projects proposed by Staff, the AG, and CUB-City." AG Ex. 4.0 at 12-13; AG Ex. 4.3. The same response clarifies that public safety will not be jeopardized by any reduced discretionary investments made by PGL if traditional average rate base calculations are used in the forecasted test year, by indicating, "The Utilities maintain a safe and reliable system. They have never claimed that accelerated main replacement is necessary to avoid significant reductions in safety and reliability."

For his part, Company witness Hengtgen acknowledges that a future test year, as employed by the Utilities, would typically be based upon a simple average of the rate base amounts at December 31, 2012 and December 31, 2013, as reflected in the AG-proposed revenue requirement calculation. Mr. Hentgen states at page 8 of his Rebuttal that, "First, I agree that the test year chosen by the Utilities is future in nature and is for calendar year 2013. I also agree that the proposal of an average rate base would typically be a simple average of the rate base amounts at December 31, 2012, and December 31, 2013." NS-PGL Ex. 27.0 at 8. Moreover, Mr. Hengtgen recognizes no difference in the regulatory lag that arises from using a future test year as compared to an historical test year. For instance, he fails to note that with an historical test year, the utility must first make the capital investments in new utility plant and then seek recovery only after the investments have been made. This entails considerably more regulatory lag than a future test year, where new utility rates are set based upon estimates of future capital spending. As noted above, under these circumstances, when relying on historical test year data, this Commission and many others around the country routinely allow use of a year-end rate base, with annualized revenue and cost adjustments at year-end, in an effort to reduce the regulatory lag arising from ratemaking that requires actual spending prior to rate recovery.

Mr. Hengtgen also makes note in his Rebuttal that while the Commission has approved a year end rate base when historical test years are employed, "[t]he matching principal as formulated by Staff and these intervenors is not applied in those situations to require an average rate base." NS-PGL Ex. 27.0 at 8. But what Mr. Hengtgen fails to recognize is that the vast reduction in regulatory lag that occurs when using a future test year eliminates any need to modify the matching principle to the year-end rate base approach that is often employed when using an historical test year. AG Ex. 4.0 at 14.

In his surrebuttal testimony, Mr. Hengtgen offerred for the first time, what he characterized as "an attempted compromise", an alternative that calculates a September 30, 2013 rate base amount for the Commission to consider. NS-PGL Ex. 43.0 at 10. This so-called compromise introduces an entirely new set of rate base numbers not previously filed by the Utilities, including new Plant Additions, accumulated depreciation, deferred income taxes and all the other elements of the new, alternative rate base. This eleventh-hour compromise of sorts should be rejected by the Commission. While moving the previously proposed December 31 end of year forecasted numbers forward by three months, it still fails to provide an equitable representation of the average plant investment (and other rate base element) values that better reflect the Company's actual capital costs in the test year.

For all of these reasons, the Companies proposal to employ a year-end rate base in the calculation of the revenue requirement in this case should be rejected, and Mr. Effron's adjustments to reflect an average rate base for both the PGL and NS rate bases, as detailed in AG Ex. 5.1, Schedules DJE-1P and DJE-1N, should be adopted.

2. Plant

a. Forecasted Test Year Capital Additions – Utility Plant in Service (NS)

b. Accelerated Main Replacement Program Projects (PGL)

The AG argues that Peoples Gas is asking ratepayers to cover in rates AMRP investments that include a projected test year level of $220 million. These AMRP investment amounts promise to remain high for years to come as the Company seeks to replace approximately three thousand miles of cast iron main and associated infrastructure over the next few decades. From the outset, it should be noted that the People do not debate whether outdated, brittle, or otherwise dangerous gas mains or segments should be replaced. If the mains in question are threatening public safety or interfering with the delivery of reliable service, then the mains must be replaced. However, given the significant dollar amounts associated with the AMRP cost recovery from ratepayers, compounded with the critical safety claims made by the Company related to this project, the People have serious concerns about the spiraling costs and PGL's lack of clear work plans. The People support Staff witness Buxton's proposal to engage an independent audit of the Company's expenses, methodology, and work plans. The Commission has clear authority under Section 8-102 and general authority under Section 8-505 of the Act to ensure "to require every public utility to maintain and operate its plant, equipment or other property in such manner as to promote and safeguard the health and safety of its employees, customers and the public… ." 220 ILCS 5/8-505. Included within this investigation should be a re-examination of the viability and reasonableness of the 2030 estimated completion date from safety, reliability and economic perspectives.

The Public Utilities Act requires the Commission to establish just and reasonable rates. 220 ILCS 5/9-101. In order to include an investment in rate base, that investment must be both prudently incurred and used and useful. 220 ILCS 5/9-211. It is the Commission's duty to determine whether capital improvements or additions to plant are reasonable. *Business and Professional People v. Ill. Commerce Comm. ("BPI II"),* 146 Ill. 2d 175, 196 (1991). Based on the record evidence in this docket, the Commission should have concerns that the project is being reasonably and efficiently managed. The record evidence supports closer Commission scrutiny.

The Company repeatedly hinges its commitment to timely completion of this project "if appropriate and timely recovery is provided." See, *e.g.*, NS/PGL Ex. 34.0 at 11. Mr. Hayes spent approximately four pages of his six page supplemental direct testimony discussing unforeseen costs and various costs that are outside the Company's control. *See, generally*, NS/PGL Ex. 21.0 at 2-5. However, he dedicates no more than *two lines* of his testimony discussing the prudence of spending on this project. In fact, he merely presents the conclusory and dismissive explanation that: "The capital expenditures incurred as a result of the project are or will be prudently incurred, reasonable in cost, and used and useful in providing utility service." NS/PGL Ex. 21.0 at 6. Despite the dramatic increases in costs year over year, the Company simply admits that it "cannot control the unexpected." NS/PGL Ex. 34.0 at 10.

The Company's attempts to outline cost saving mechanisms that it has in place backfire and instead demonstrate the fact that ratepayers are getting less plant investment for more money. Mr. Hayes, when discussing the reasonableness of spending hundreds of millions of dollars every year, testifies as to "rigorous cost reducing measures." NS/PGL Ex. 34.0 at 10-11. However, closer analysis reveals that these "rigorous cost reducing measures" primarily include "suspending a portion of the 2012 planned construction work, completing active projects to a safe condition if we could not complete them in total, suspending all overtime, re-prioritizing the work being performed by Peoples Gas crews, suspending consulting engineers work, and reducing contracted staff." NS/PGL Ex. 34.0 at 10. Essentially, in order to save money and cut costs, the Company is stopping the very work that they claim is critical to safety and reliable delivery of utility service. Despite the Company's "rigorous cost reducing measures," Mr. Hayes admitted that the Company still spent $12 million more than it had originally budgeted. NS/PGL Ex. 34.0 at 11. Indicative of this overspending is that, apparently, one of the ways in which PGL seeks to save money and control costs is to start new pilot programs and spend more money. PGL lists as one of the efforts to control costs the development of a pilot for the cross-bore program. NS/PGL Ex. 34.0 at 11-12. As noted in the Cross Bores Section of this brief, this is a program that, itself, is adding almost $6 million in unjustified expenses and is rife with problems. Regardless, the cross-bore program was being investigated as early as the 1990s, (Tr. at 373), so the People are uncertain how this additional program is only now being launched as a pilot. It is equally unclear as to how it will save costs on AMRP.

PGL needs to demonstrate that it can appropriately manage its costs, something Staff's engineering witnesses believe it has not shown. See ICC Staff Ex. 16.0 at 22; ICC Staff Ex. 20.0 at 17. Since this docket began, the projection for AMRP expenses has been a moving target, to say the least. By the time rebuttal testimony was filed, the 2012 budget had increased by 10% to $220 million. NS/PGL Ex. 21.0 at 1. Further troubling is that throughout this docket, PGL's cost estimates have varied wildly between testimony filing dates, and the Company appears to shift much of the blame for this on "unforeseen conditions." NS-PGL Ex. 21.0 at 1. The People acknowledge that the reality of running a project of this size is that costs will vary and unforeseen events will arise that cause increases in spending. PGL's cost overruns, however, should be a red flag to the Commission and proof that the project requires additional scrutiny.

In fact, as AG witness Mr. Effron noted, by PGL's own estimates, the non-budgeted and unforeseen conditions would have increased the total cost of AMRP additions in 2012 by $62 million based on the scope of work originally budgeted for 2012. AG Ex. 2.0 at 9. However, the magnitude of the cost increases was reduced by $42 million by decreasing the scope of the work, including the suspension of work on low priority projects and the suspension of non-critical overtime hours being charged to AMRP by PGL'S work crews. NS/PGL Ex. 21.0 at 5-6. Through the end of September, the actual spending on cast and ductile iron main replacement in 2012 was approximately $21.6 million above the budgeted level of such spending. AG Cross Ex. 9.

PGL installed 154.5 miles of mains in 2011[3] and 92.1 miles of mains in 2012.[4] PGL Ex. 34.3. In his rebuttal testimony in this case filed in December of 2012, Mr. Hayes stated that "Peoples has still completed only 95 percent of work intended for 2011 and less than 50 percent of work intended for 2012. NS-PGL Ex. 34.0 at 10. Further, Mr. Hayes says that "Peoples will reduce the amount of work it will complete in 2013. *Id.* at 11. Finally, Mr. Hayes summarized the crux of the problem with the Company's AMRP when he testified that the Company "is in a position where additional dollars will be spent while at the same time less volume of work will be accomplished." NS/PGL Ex. 21.0 at 1. By their own admission, the Company seems to be asking ratepayers to pay more and receive less.

[3] It is unclear, however, whether the 2011 total reflects mains that were scheduled to be replaced in 2009 or 2010.
[4] This total does not include replacements of mains in 2012 that were scheduled to be replaced in 2011.

Related to the Company's demands for recovery is the question of timing. The Commission explicitly noted the importance of timely completion of AMRP in 09-0166/09-0167:

> Due to the many benefits that the accelerated plan provides to ratepayers, the Commission is of the opinion that time is of the essence and hereby requires completion of the acceleration plan project by 2030.

ICC Docket 09-0166/09-0167 Final Order (January 21, 2012) at 196.[5] In that case, the People questioned the validity of the 2030 date because it was rooted in a very high-level, economic analysis for the purpose of gaining approval of Rider ICR – not on any kind of safety and reliability analysis.[6]

Regardless of the 2030 date's validity, the Company has made it clear that it no longer considered itself *required* to achieve that completion date since the reversal of the Commission's decision in Docket No. 09-0166/0167 approving Rider IC R. AG Cross Ex. 9. Staff witness Buxton testified, "the Commission still needs assurance that Peoples has a plan to complete its AMRP in 20 years as both Peoples and the Commission seemed to intend in the January 21, 2010 Order in Docket No. 09-0167." ICC Staff Ex. 20.0 at 23. This assurance is lacking in the instant docket. The only difference following the "acceleration" of the program is that the Company, as noted above, rests timely completion on being provided "appropriate and timely recovery." NS/PGL Ex. 34.0 at 11. The Company wavers even further in its response to AG Data Request 22.01, when the Company explained that "if, over time, Peoples Gas does not recover the costs of the AMRP projects, then at some point funding the AMRP projects will become infeasible as a matter of practical business reality." AG Cross Ex. 15. Therefore, it is unclear what financial conditions meet the Company's test of adequate cost recovery for purposes of continuing the program. As part of any audit, the Commission should revisit the validity of the 2030 completion date to ensure that it comports with standards of safety, reliability, and cost-efficiency.

Historically, too, PGL has failed to provide a solid work plan. As the People noted in its Initial Brief in ICC Docket 09-0166/09-0167:

> The fact that Peoples is unwilling to formally commit to a specific plan or schedule for Commission approval takes on new meaning when considered with a Rider ICR proposal that permits surcharges to be assessed on the first dollar of investment in the applicable six plant accounts.
>
> The Company's request to approve a cost recovery mechanism before the Commission has even evaluated a specific implementation plan for any acceleration proposal is a classic case of putting the cart before the horse that should be rejected out of hand by the Commission.

ICC Docket Nos. 09-0166/09-0167 AG Corrected Initial Brief at 27-28, filed on e-docket on September 30, 2009.[7] That same problem seems to be present in this docket. and the Company asks the Commission and ratepayers, to trust them and not sweat the details of a

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[5] The People acknowledge that the portion of the Final Order in this docket was overturned by the Appellate Court in *People ex. rel Madigan v. Illinois Commerce Comm'n*, 2011 IL App (1st) 100654. However, the language of the Order in 09-0166/09-0167 is still representative of the Commission's original intent related to AMRP.

[6] PGL examined three different timing scenarios for acceleration: 2025, 2030 and 2035. Tr. 809; PGL Ex. SDM-1.0 at 50, 51. The Companies' witness at the time, Mr. Marano, concluded that a 2030 completion date would be the "most practical and economical" of the three choices. ICC Docket No. 09-0166/0167, Tr. at 810.

[7] The People ask that the Commission take administrative notice of the existing record in the Company's previous dockets where the parties are largely the same and similar issues are being addressed.

project that spans decades and will costs hundreds and hundreds of millions of dollars. The primary plan presented by PGL in support of AMRP is its Five-Year Construction Plan. *See* ICC Staff Ex. 20.0 at Appendix 2. Mr. Buxton characterized this as "a discussion of how Peoples intended to create a plan" rather than a detailed outline of a plan to allocate resources and begin construction. ICC Staff Ex. 20.0 at 19.

In the opinion of Staff witness Roy Buxton, "a public utility that has been digging up Chicago streets for over 150 years should have known enough to take into consideration the resource limits of the City of Chicago's various construction-related departments and offices." ICC Staff Ex. 20.0 at 16. However, by the Company's own admission, it is not making coordination of efforts a priority. In response to AG Data Request 10.17, the Company acknowledged on October 26, 2012 that:

> To date there has been no correspondence between Peoples Gas and the City of Chicago's Department of Transportation or Office of Underground Coordination in regards to forecasted 2013 AMRP expenditures on needed number of pipe location digging requests, construction permit requests, or City marking of existing underground facilities requests.

AG Cross Ex. 8. Despite being deep into 2012 calendar year, PGL had not yet had any correspondence or coordination with the City. It is this very lack of action on the part of the Company that is alarming to the People and demands Commission oversight. Indeed, as Mr. Buxton notes, other utilities operating in the City of Chicago do not appear to have such issues with coordinating their activities. ICC Staff Ex. 20.0 at 16-17.

The current protocol for replacing mains is unclear at best. Generally speaking, gas main segments which score above a 6.0 on the Main Replacement Index (MRI) scale represent a threat to safety. AG Cross Ex. 9. However, six segments with MRI above 6.0 remained unrepaired in 2012 with an unclear date on which they will be replaced. AG Cross Ex. 9. The Company's cryptic response to City data request dated November 13, 2012, on this very issue simply noted that:

> Gas main segments currently on the list will be replaced in 2012 or 2013. Only one segment is listed as being replaced in 2013 as it is part of the "2013 construction work" which will be awarded to a construction contractor in 2013 while the other segments were previously awarded for replacement as part of the "2012 construction work."

AG Cross Ex. 9. Currently, main segments with a Main Ranking Index (MRI) above 3.0 (which are viewed as "possible replacement candidates") account for only 3.2% of all of the main segments to be replaced. AG Cross Ex. 9; PGL Response to AG Data Request 10.16. There are, therefore, an arguably small number of mains in seemingly dire need to be replaced. Yet, the record evidence suggests that the Company has not made the replacement of these mains a priority. AG Cross Ex. 9. Despite such a relatively small percentage of "possible replacement candidate" mains, it does not appear that PGL took into account these mains when crafting their "zonal" approach, described in its Brief. See NS/PGL IB at 35. These inconsistencies in prioritization are unexplained and further support the need for more Commission oversight of the AMRP project.

Of additional concern to the People is that excessive authority may rest with the "shop manager" in determining whether certain mains will be replaced. The Company stated, in response to City Data Request 2.05 that "The shop manager has the authority to have gas main segments replaced based on field conditions regardless of the MRI value. Each situation is evaluated on a case-by case basis." AG Cross Ex. 9. More detail is needed for the Commission's review on whether this line of authority is reasonable.

In summary, as Mr. Buxton testified, "There is no reliable evidence before the Commission to allow it to determine how long Peoples will take to complete its AMRP or what the completed AMRP will cost." ICC Staff Ex. 20.0 at 25. Given the strong concerns that Staff has for the implementation of the Company's AMRP and the concerns raised by the People in this brief, the People urge the Commission to conduct an investigation of PGL's AMRP to determine whether the project has been or will be prudently undertaken and whether it is reasonable in cost.

As noted earlier, Section 8-102 of the Act (220 ILCS 5/8-102) grants the authority to the Commission to conduct such an audit. In relevant part, that section reads that:

> The Commission is authorized to conduct or order a management audit or investigation of any public utility or part thereof. The audit or investigation may examine the reasonableness, prudence, or efficiency of any aspect of the utility's operations, costs, management, decisions or functions that may affect the adequacy, safety, efficiency or reliability of utility service or the reasonableness or prudence of the costs underlying rates or charges for utility service. The Commission may conduct or order a management audit or investigation only when it has reasonable grounds to believe that the audit or investigation is necessary to assure that the utility is providing adequate, efficient, reliable, safe, and least-cost service and charging only just and reasonable rates therefor, or that the audit or investigation is likely to be cost-beneficial in enhancing the quality of service or the reasonableness of rates therefor.

220 ILCS 5/8-102.

Therefore, in light of the evidence in the record supplied by the Company, coupled with the testimony of Mr. Buxton, the People support Staff's conclusion that the Commission has "reasonable grounds" to conduct a necessary audit to ensure that PGL is conducting its AMRP in the most reasonable, prudent, and efficient manner possible.

c. Construction Work in Progress (PGL)

AG witness Effron, following a careful analysis, discovered that PGL overstated the amount of test year plant in service because the AMRP will not be placed in service on the schedule contemplated by PGL. Section 9-212 of the Public Utilities Act (220 ILCS 5/9-212) requires that, in order to be included in a utility's rate base, the utility must prove (and the Commission must determine) that additions to existing plant are both prudent and used and useful in providing utility service to the utility's customers. The Construction Work in Progress (CWIP) balance represents the amount of construction in progress that has not yet been placed into service, and thereby cleared, into plant in service – by its very definition CWIP cannot be used and useful. As discussed in greater detail below, ratepayers should not be forced to pay for large balances of AMRP plant that are still works in progress and not currently used and useful in the provision of utility service. The People's adjustment seeks to remedy this by reducing the average balance of test year plant in service.

The People's adjustment is reasonable because it removes a substantial balance of AMRP construction in progress from the test year plant in service. Per PGL's own data, a substantial balance of AMRP plant sat in CWIP for each month in 2012 through November. See AG Ex. 5.2 at 10, 12. This balance increased from $20.0 million in January to $100.7 million in August and then decreased somewhat, but was still $61.1 million as of November 2012. See AG Ex. 5.2 at 9, 10. This stands in sharp contrast to PGL's budgeted level of

AMRP plant in CWIP as of November 2012, which was zero. AG Ex. 5.2 at 8. The net result of this is that $61.1 million of AMRP plant that the Company had originally budgeted to be in service as of November 2012 was still sitting in CWIP, and was not, in fact, in service. This makes it clear that AMRP plant is not going into service on the schedule anticipated by Peoples Gas.

Company witness Mr. Hengtgen asserts that the balance at September 30, 2012 will likely be cleared to plant in service at some point in 2013. NS/PGL Ex. 27.0 at 34. However, even if we take this highly dubious and optimistic projection as true, PGL also forecasts almost *$221 million* of spending on AMRP plant in 2013. Yet, PGL's forecasted 2013 year-end balance of CWIP is only $182,000. NS-PGL Ex. 19.2P, Sched. B-5 at 2. Therefore, for the purpose of determining its test year rate base, PGL is implicitly assuming that substantially all of its AMRP spending in 2013 will be complete and in service by the end of the year. This assumption is not only unrealistic, it harms ratepayers by making them pay an artificially inflated rate until the next rate case.

As further evidence of the unrealistic and perhaps contradictory nature of this critical assumption, PGL stated in response to AG Data Request 14.08, that "It is expected that the [AMRP] projects in CWIP between January and August 2013 will be in service by December 2013 or early 2014." AG Ex. 5.2 at 12. Therefore, it seems as though even some of the AMRP projects commenced in the first eight months of 2013 will not be going into service until 2014.

It should be noted that PGL made no representations about the in-service timing of any AMRP plant in CWIP in the last four months of 2013 in its written testimony. However, by the Company's own admission at the evidentiary hearing, AMRP projects begun in the third quarter of 2012 were not likely to be placed into service in 2012. Tr. at 184. The Company has not yet estimated when the projects begun in the third quarter of 2013 will be placed into service, but it is likely that they will not be placed into service in 2013. Tr. at 184.

The Company's assumption would require the highly unlikely assumption that all of the AMRP projects in 2012 and 2013 will be used and useful for the 2013 test year. Based on Mr. Effron's analysis of the information provided by PGL, it is "highly unlikely" that all of the AMRP projects in 2012 and 2013 will be used and useful in providing utility service in the 2013 test year in this case. AG Ex. 5.0 at 9. Therefore, the forecast of utility plant in service in the Peoples Gas 2013 rate base should be adjusted. The AG proposal resolves PGL's unrealistic assumption that it will clear substantially all of the AMRP spending in 2013 to plant in service.

The premises upon which the People base its recommendations are far from "faulty and uninformed" as PGL witness Hentgen complains. PGL Ex. 27.0 at 33. The AG recommendation is, in fact, a very reasonable solution to the problem presented by both the inherent month-to-month fluctuation of CWIP and the Company's unrealistic assumptions. AG witness Mr. Effron analyzed the average balance of AMRP plant in CWIP for the first 11 months of 2012 and found the average to be $56,114,000, a number he deemed to be representative of the average balance of CWIP as new AMRP projects are added and completed AMRP projects are placed into service.

As further explained by Mr. Effron, PGL itself projected an average balance of $4,639,000 of CWIP in its 2013 test year rate base (NS-PGL Ex. 19.2P, Schedule B-5, Page 2), which is not unreasonable. However, the estimated average 2013 balance of AMRP plant in CWIP in excess of $4,639,000, which will not be used and useful in providing utility service in the test year, should be eliminated from the PGL test year rate base. This adjustment reduces the test plant in service included in rate base by $51,476,000 (Exhibit AG 5.1, Schedule DJE-1.3P). Net of offsetting adjustments to depreciation reserve and accumulated deferred income taxes, the appropriate net adjustment to the PGL test year rate base is $36,284,000

(Id.). The reduction to test year plant in service results in derivative reduction to test year depreciation expense of $1,935,000 (Id.).

Therefore, the AG concludes that the Commission should adopt the AG's fair and reasonable proposal because it corrects an unfair and unrealistic projection of AMRP spending to be transferred to plant in service and the Company has not proven that its projected amounts to be placed in plant in service represent additions that are used and useful in providing utility service.

d. Non-Union Wages (see also Section V.C.2)

e. Capital Costs for Non-AMRP Gas Services

3. Cash Working Capital ("CWC")

NS-PGL Exhibits 19.3P and 19.3N set forth the updated lead lag study of CWC for both companies, as sponsored by NS-PGL witness Hengtgen. AG witness Brosch incorporated a calculation of CWC within AG Exhibit 4.3 and AG Exhibit 4.4 at Schedule B-5 that recognizes most of the lead and lag day values that are sponsored by Mr. Hentgen in the Companies' lead lag studies, but proposes two important modifications to the Companies' CWC analysis to ensure that ratepayers do not supply a CWC windfall to NS and PGL.[8] Mr. Brosch's analysis proposes two revisions to the Companies' lead/lag input values to:

- Assign a zero revenue lag day value to Pass Through Taxes, to incorporate the Commission's treatment of this issue in all recent major rate cases, and
- Assign the Other O&M lag day value to Pension and Other Post Employment Benefit ("OPEB") expenses in place of the Companies' assumed zero payment lag value for these expenses.

While Mr. Brosch noted that he does not agree with the Companies' use of arbitrary mid-points within broad 30-day wide ranges of collected receivables balances to estimate the average revenue collection lag, he has not revised the resulting revenue lag values used by the Companies in deference to recent Commission decisions that do not reject or modify the mid-point estimation methodology.

a. Pass-Through Taxes

In the Commission's 2012 (NS-PGL) Rate Order, the Commission assigned a zero revenue lag to pass-through taxes. 2012 Rate Order at 27. This adjustment should be made again in this docket because the Companies collect additional charges for pass-through taxes through a rider tariff and are not responsible for remittance of such taxes until after they collect revenues from ratepayers. The tariff captioned Rider 1 Additional Charges for Taxes and Customer Charge Adjustments provides for additional charges to customers where NSG and PGL act as collection agents for State and local governments in the collection and remittance of taxes. This process is unique and results in pass-through taxes becoming

[8] Notably, these calculations do not update the input amounts used to calculate CWC in column B in an effort to: 1) focus attention upon the value of disputed lead lag study issues without introducing other variables into the calculation, and 2) recognizing that the Commission customarily updates CWC calculations using final approved income statement values within the Appendices attached to its Final Orders. Obviously the final, Commission-approved income statement values are not available at this time to calculate a final CWC value for the Companies.

balance sheet transactions that do not create either gas revenues or tax expenses on the Companies' income statements.[9]

Pass-through taxes are not a liability of the Companies that must be paid before taxable revenues have been collected from customers. The Illinois laws and regulations that provide for the collection and payment of pass-through taxes by the Companies indicates that such taxes are payable based upon the amounts of *collected* revenues. For example, the Illinois Gas Use Tax provided for at 35 ILCS 173/5-15 states that, "The tax collected by any delivering supplier shall constitute a debt owed by that person to this State." Similarly, the Municipal Utility Tax provided for at 65 ILCS 5/8-11-2 is a tax on "Gross Receipts" which is defined as, "…the consideration received for distributing, supplying, furnishing or selling gas for use or consumption and not for resale." The Chicago Gas Use Tax at Chapter 3-41-050(6) of the Municipal Code of Chicago provides for Collection of Tax noting that, "The public utility shall not be liable to the city for any tax not actually collected from a retail purchaser." AG Ex. 1.0 at 53-54.

To reflect the fact that Pass-Through Taxes are not a liability that requires CWC, Mr. Brosch modified Schedule B-5 to effect proper treatment of pass-through taxes by assigning a zero revenue lag day value to the cash inflows that are associated with the Companies' collection of pass-through taxes at line 2 of Schedule B-5 in both AG Exhibit 4.3 and AG Exhibit 4.4. Both Staff witness Kahle and CUB witness Smith proposed identical adjustments.

In response to this justified modification to the Companies' CWC calculation, NS-PGL Hengtgen argued that Mr. Brosch's assignment of a zero revenue lag day value for pass-through taxes is "incorrect and illogical" and that no "analysis or quantitative support" for doing so has been provided by either Mr. Brosch or Staff witness Mr. Kahle.[10] These claims are invalid for several reasons. First, the assignment of a zero revenue lag day value is entirely correct and quite logical because these taxes are incurred because of, and at the time of, the collection of taxable revenues by the Companies. The relevant statutes and municipal codes[11] show this to be true, and the Commission endorsed that position in its recent rate Orders.[12] There is no need for "analysis or quantitative support" for utilization of zero revenue lag days because of the fact that pass-through taxes become payable when revenues have been collected by the Companies.

In fact, Mr. Hengtgen admits that pass through taxes, with the exception of the ICC Gas Revenue Tax, are due and payable upon (or after) collection, as both Mr. Brosch and Mr. Kahle assert. In response to Data Request PGL 16.21, the Companies stated, "Mr. Hentgen agrees and does not have to assume that for the pass through taxes listed on NS-PGL ex. 27.13P and 27.13N, with the exception of the ICC Gas Revenue Tax, the amounts are due and payable upon (or after) collection. These facts have been discussed and identified in Mr. Hengtgen's direct testimony and rebuttal testimony and are clearly presented in its lead lag study, WPB-8. However, Mr. Hengtgen cannot assume that 'no revenue lag is applicable'. There is a cash inflow of these funds to the Utilities, therefore there is a lag and it is identical to the lag as explained in Mr. Hengtgen's direct and rebuttal testimonies. Therefore, no modifications to the Utilities' lead day values can be calculated and is not required." That data request response appears in AG Exhibit 4.10, along with copies of the relevant pages

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[9] See Part 285.315(a) at page 262 showing taxes accrued for State Public Utility, Gross Revenue, Illinois Gas Use, Municipal Utility and Chicago Sales & Use taxes with no corresponding distribution of such taxes to expense account 408, Taxes Other Than Income Tax expense.

[10] NS-PGL Ex. 27.0 at 15.

[11] AG Ex. 1.0, page 53.

[12] *See*, e.g., 2012 Rate Order at 27.

from the referenced WPB-8 that were used by Mr. Hengtgen to calculate the pass through tax payment lead day values.

Mr. Brosch adopted and used Mr. Hengtgen's calculated pass through tax lead day values in his calculation of CWC. Mr. Hengtgen continues to support the payment lead day values he sponsored in direct testimony, while mysteriously concluding that assignment of a zero revenue lag to the related customer remittances within the AG and Staff lead/lag adjustments now makes Mr. Hengtgen's payment lead day values for these taxes suddenly become unreasonable and illogical. This position makes no sense. The lead day values that were calculated by Mr. Hengtgen were reasonable for use by Mr. Brosch and by Staff in calculating the Companies' cash working capital for the test year. The calculations shown on the Companies' WPB-8 for pass-through taxes clearly show that specific revenue "collection assumptions" were used to calculate the total amounts of taxes actually paid for each month of 2011. These workpapers reflect that actual taxes paid by PGL each month relate to revenues billed in the current "service month" as well as revenues earned in three prior months, which are designated "Service Month +1", "Service Month +2" and "Service Month +3" in the workpapers. This fact causes PGL to experience longer lead days for pass through taxes than other Illinois utilities, which allows the Company to hold the cash for these pass through taxes longer than would appear to be possible under the applicable statutory payment due dates for such taxes. AG Ex. 4.0 at 58-59.

In his rebuttal testimony, however, Mr. Hentgen included new exhibits 12.12P and 12.12N for the apparent purpose of characterizing Mr. Brosch's (and Staff's) reliance upon the Companies' calculated pass through tax lead day values to be unreasonable and illogical. Mr. Hengtgen explains that his NS-PGL Ex. 27.12P shows the possible collection and due dates for Peoples Gas' Gross Receipts/Municipal Utility Tax ("MUT"), the City of Chicago Gas Use Tax ("City GUT"), the Energy Assistance Charges ("EAC") and the Gross Revenue/Public Utility Tax ("GRT"), stating "for an example month (September 2012) and when the amounts would be due based on all the possible collection dates in the example month. Mr. Hengtgen then concludes with what he calls a "side by side comparison" of the Company's calculated lead day values compared to the maximum and average number of "days held" with columns showing calculations of "Days Staff and AG Proposal Exceeds" the "Max" and "Average" of the "Days Held" derived by Mr. Hengtgen from his exhibits NS-PGL 27.12P. NS-PGL Ex. 27.0 at 22 .

This NS-PGL position is simply odd because either Mr. Hengtgen's asserted pass through tax payment lead days are reasonable, or they are not. How and when the Utilities pay pass through taxes is a factual determination without regard to measurement and application of revenue lag days to the related cash inflows. It would appear that Mr. Hengtgen is attempting in rebuttal to disparage his own calculated payment lead day values for pass through taxes, in an effort to somehow rationalize applying a full revenue lag to the related cash inflows. Mr. Hengtgen's calculations in PGL WPB-8 reveal an important difference in the timing of the Companies' actual tax remittance payments that is completely inconsistent with the assumptions now being used by Mr. Hengtgen in his rebuttal NS-PGL Ex. 27.12P. AG Ex. 4.0 at 60.

In addition, PGL does not actually pay pass through City of Chicago Gas Use Tax revenues pursuant to the "Day Collected" and "Due Date" periods shown in NS-PGL Ex. 27.12P. Actual monthly payments are based upon 25% of the current month's revenues, plus 50% of the prior month's revenues, plus 15% of the revenues from the month before the prior month, plus 10% of the revenues from the third prior month, as shown in PGL WPB-8 for "Taxes-Pass Through-Chicago Gas Use Tax" and not the "Number of Days Held" as shown in rebuttal NS-PGL Ex. 27.12P. Mr. Hengtgen's rebuttal exhibit displays hypothetical payment patterns that are vastly different from the Company's actual remittance patterns shown in its lead lag study workpapers. The same inconsistency exists for the "Energy Assistance Charges" in NS-PGL Ex. 27.1P when compared to the "Taxes-Pass Through-EAC" analysis of actual payments in PGL WPB-8, and for "Public Utility Tax" in NS-PGL Ex. 27.1P when compared to the "Taxes-Pass Through-GRT/MUT" actual payments analyzed in PGL WPB-8. AG Ex. 4.0 at 60-61.

All of that being said, the Commission should nevertheless rely upon the payment *lead day* values sponsored by Mr. Hengtgen in his direct testimony and calculated in WPB-8 for the timing of payments of pass through taxes. As Mr. Brosch testified, this appropriate because the "Collection Assumptions" used therein are reflective of agreements made with the City of Chicago that the Companies have apparently now adopted to delay remittances of other types of pass through taxes. This distinction is referenced in Mr. Hengtgen's Rebuttal where he describes the PGL agreement (PGL Ex. 7.3) with the City of Chicago ("City"), which governs how these taxes are paid. In accordance with that agreement, Peoples Gas pays and remits the MUT and the City GUT on the basis of estimated cash receipts *regardless* of whether or not the amounts are received from customers. The estimated cash receipt percentages are based on a four-month collection period as identified on page 2 of the agreement. *See* PGL Ex. 7.3. Mr. Hengtgen used these collection percentages in his lead lag study (WPB-8, pages 45-56) in order to properly reflect the lead values as proposed by Peoples Gas. Mr. Hengtgen stated that because the agreement with the City requires the use of fixed estimated collection percentages and those percentages more than likely will differ from actual collections of these amounts from customers, the days held amount will not reflect the averages shown on NS-PGL. Ex. 27.12P. Mr. Hengtgen noted that after the agreement with the City was implemented, Peoples Gas decided to use a similar process for the GRT and the EAC. North Shore also follows this process for all of its pass through taxes with the exception of the ICC Gas Revenue Tax.[13] Mr. Hengtgen should not be allowed to characterize the pass through tax "Due Dates" differently in rebuttal NS-PGL Ex. 27.1N/P so as to criticize Staff and AG, when the negotiated payment due dates that are actually employed by the Companies are much more liberal and allow more delay in tax remittances, as reflected in the referenced PGL and NSG WPB-8 calculations. AG Ex. 4.0 at 61-62.

Mr. Brosch identified one needed revisions to the AG lead lag study of cash working capital in his rebuttal after review of Mr. Hengtgen's arguments. Specifically, Mr. Hengtgen states that the ICC Gas Revenue Tax is, "Different than the other pass through taxes, the ICC Gas Revenue Tax is not based on collections but 'equal to .08% of its gross revenue for each calendar year' (220 ILCS 539 5/2-202 (c))."[14] Mr. Brosch agreed with this distinction and reclassified this tax expense in AG Exhibit 4.1 and 4.2 near the bottom of Schedule B-5 so that it is no longer treated as a pass-through tax at lines 1 and 2. No other modifications to the AG-proposed CWC adjustments described and detailed in Mr. Brosch's testimony and exhibits are needed. AG Ex. 4.0 at 62.

Mr. Hengtgen further challenged Mr. Brosch's use of the term "lag" versus "lead" in his rebuttal, stating, "While this may seem like a minor technical point, it may be a part of the reason this issue is being contested and is confusing to people that (sic) are not familiar with 1) a lead lag study, 2) pass through taxes generally, and 3) how these cash flows (inflows and outflows) work." This condescending and and flippant suggestion that Mr. Brosch was somehow confused is unproductive. In fact, Mr. Brosch has worked with lead lag studies in multiple regulatory jurisdictions *for more than three decades.* He pointed out that the terms "lag" and "lead" can and frequently are used interchangeably by informed practitioners to reference the time difference between dates when earning or incurring a revenue or cost and

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[13] Id. page 22, lines 479-494.

[14] Id. Page 25, line 537.

the related dates of cash receipt/payment for same. Nevertheless, Mr. Brosch adopted Mr. Hengtgen's preferred terminology in this rebuttal in an effort to reduce any perceived "confusion" surrounding this matter of semantics. AG Ex. 4.0 at 63.

Mr. Hengtgen further takes issue with Mr. Brosch argument that the Utilities are only "collection agents," and asserts that the argument ignores the fact that the Utilities still require cash on hand to pay the tax by the due date because "shareholders are financing the payment until funds are collected."[15] These arguments, too, miss the mark. It is quite logical for utilities to serve as collection agents for pass through taxes through tariff Rider 1, as explained in Mr. Brosch's Direct Testimony.[16] Mr. Hengtgen's own PGL Ex. 7.3 is captioned as an "Amendment to Tax Collection Agreement" with the City of Chicago and the Companies' WPB-8 workpapers employ "Collection Assumptions" in order to calculate the relevant payment lead days for pass through taxes. In the context of ICC Gas Revenue Tax, where Mr. Hengtgen chose to dispute my "collection agent" characterization, any differences in the ratemaking treatment of cash flows has been eliminated by the modifications made to the AG calculation of cash working capital on Schedule B-5. AG Ex. 4.0 at 63-64.

In his Surrebuttal testimony, Mr. Hengtgen references again the Companies' agreement with the Cityof Chicago "to formalize and streamline this (tax collection) process" as support for his assumed collection lag related to pass through taxes. NS-PGL Ex. 43.0 at 20. But this discussion in no way clarifies the inconsistencies in Mr. Hengtgen's treatment of the pass through taxes in the lag calculations of his lead lag study and the agreement that the Company maintains with the City of Chicago. The fact remains that PGL experiences longer lead days for pass through taxes than other Illinois utilities, which allows the Company to hold the cash for these pass through taxes longer than would appear to be possible under the applicable statutory payment due dates for such taxes. Mr. Brosch's well-supported adjustment should be adopted.

b. Pension/OPEB

The AG notes that Companies' Schedule B-8, at page 1, line 8 assigns a zero expense payment lead value of Pension and OPEB expenses. When the same dollars for collection of revenues associated with these expenses are assigned a full revenue lag at line 1 of Schedule B-8, the resulting CWC requirement included in rate base is significantly increased. AG witness Brosch testified that Pension and OPEB expenses are not paid currently in cash each year, such that proper lead lag study treatment of these expenses is easily determined. In order to correct this inequity, Mr. Brosch applied a more reasonable lag day value that better reflects the reality of the varied Pension and OPEB accruals.

Mr. Brosch explained that Pension and OPEB expenses are based upon accounting accruals, rather than regular and scheduled payments to vendors like other cash expenses. In responding to Staff data requests on this topic, the Companies noted that, "cash payments do not equal expense accruals recorded for Pension and OPEB."[17] These responses produced payment information for funding of OPEB amounts indicating several irregularly scheduled contributions made to an insurance plan and a single pension funding payment for North Shore but no such funding for PGL in 2011. Without more information and further analysis, it is impossible to discern a reliable payment lead day value from this data. This may be why Mr. Hentgen elected to assign a zero lag day value to Pension and OPEB expenses rather than rely upon an analysis of payment data.

Mr. Brosch testified that a reasonable treatment would be to assume the same payment lead day value the Companies have calculated for their payment of the many

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15 *Id.* at 25.

16 AG Ex. 1.0 at page 53.

17 AG Ex. 4.0 at 65, citing PGL/NSG responses to data requests DGK 5.02.

miscellaneous cash vouchers contained within the Other Operations and Maintenance Expense line of the lead lag study. This lead day value is indicative of how the Companies schedule and pay invoices for the many types of routinely incurred expenses that are not separately studied and listed elsewhere in the lead lag study. Notably, the Other O&M lead day value is much closer to the calculated revenue lag, which dramatically reduces the overstatement of CWC that occurs under the Companies' arbitrary assignment of a zero lead day value. AG Ex. 1.0 at 55.

He further noted that Pension and OPEB expense could be treated like all the other accrual-basis non-cash expenses such as depreciation, amortization and deferred income taxes and removed from lead lag study calculations of income taxes. This would be appropriate for Pension and OPEB expenses because these amounts are actuarially determined and the amount of recorded expense is dependent upon many variables, one of which is the amount and timing of contributions that are discretionary on the part of management within ranges bounded by tax and other regulations. To implement this treatment one could either subtract the Pension and OPEB expense amounts from the Line 1 revenues that are assigned a revenue lag or, alternatively, one could set the assumed payment lead for Pension and OPEB expense equal to the revenue lag day value. Either approach would have the effect of eliminating accrual-basis Pension and OPEB expenses from having any impact upon Cash Working Capital. AG Ex. 1.0 at 55-56.

In response to Mr. Brosch's analysis regarding the CWC treatment of Pension and OPEB expenses, Mr. Hengtgen argues that there is "nothing routine about the cash flow related to the Utilities Pension and OPEB expenses. Mr. Brosch even indicated in his testimony that the Utilities had supplied data in response to a staff data request reflecting irregular scheduled payments for pension and OPEB."[18] As Mr. Brosch explained in his Direct testimony, however, PGL and NSG arbitrarily assumed a zero payment lead day value for pension and OPEB expenses as if there is no cash flow related to pension and OPEB expenses, causing an overstatement of cash working capital because a positive revenue lag was assigned by PGL/NSG with no corresponding expense payment lead.[19] In response to Staff data request DGK 5.02, the Companies provided information showing a single pension funding for North Shore Gas in January of 2011 and no pension funding payments in 2011 for PGL. With regard to OPEB expense, the same response provided OPEB funding payments that were front-loaded in February of 2011. Using this data and assuming a calendar year analysis period would produce an exceptionally large apparent prepayment of OPEB and pension expenses for NSG, and a meaningless pension lead day value for PGL since no PGL pension funding occurred. This irregular pattern of payment timing was <u>not</u> relied upon by Mr. Hengtgen in his rebuttal calculation of CWC in NS-PGL Ex. 27.10P/N and is not reliable enough for use in the AG's calculation of CWC.

A more normal pattern of cash disbursements is reflected in the Companies' analysis of miscellaneous expense payments for the line item captioned "Other Operations and Maintenance" in its lead lag study. Rather than accepting Mr. Hengtgen's arbitrarily assumed zero payment lag for pension and OPEB expenses, Mr. Brosch recommended the Other O&M lead day timing as indicative of the Companies' normal payment patterns for routine cash disbursements. Accordingly, the Commission should adopt Mr. Brosch's adjustment, detailed in my Direct testimony and in AG Ex. 4.1 and 4.2 at Schedule B-5, line 8, in column C.

c. All Other

18 NS-PGL Ex. 27.0 at 30.

19 AG Ex. 1.0 at 54-55.

4. Retirement Benefits, Net

In his direct testimony, the People's witness Mr. Effron made an appropriate adjustment to rate base to account for net retirement benefits, and updated those adjustments in his rebuttal testimony after reviewing the rebuttal testimonies of NS/PGL witnesses Hentgen and Phillips. AG Ex. 2.0 at 12-13; AG Ex. 5.0 at 3; AG Ex. 2.1. As Mr. Effron explained in his direct testimony, net retirement benefits are comprised of two components: prepaid pension asset – or the effect of pension fund contributions in excess of pension costs – and the accrued liability for future post-retirement benefits other than pensions ("OPEB"). The People, in line with the findings of several past Commission orders as well as testimony presented by Staff Witness Pearce and CUB/City Witness Smith, propose eliminating pension balances from rate base, treating the accrued liability for post-retirement benefits as rate base deductions, and eliminating the accumulated deferred income taxes related to prepaid or accrued pensions.

The People's adjustments are directly supported by the Commission's findings in ICC dockets 07-0241/07-0242, 09-0166/09-0167, and 11-0280/11-0281 on the appropriate treatment of the Companies' retirement benefits as part of rate base. As reflected in these decisions the Commission has routinely concluded that accrued OPEB liability should be reflected in rate base but that the pension balances should not be recognized in the determination of rate base. This notion was explicitly stated by the Commission in its Final Order in 11-0280/11-0281:

> The Commission agrees with both Staff and [Intervenors] concerning the adjustments to rate base made to account for net retirement benefits. Staff witness Ebrey agreed with GCI witness Effron's approach which removed the Utilities' respective net pension assets from rate base, but kept the OPEB liabilities in rate base. Staff and GCI's adjustments are supported by the evidence and remain consistent with the Commission's conclusions about the pension asset in the 2007 and 2009 PGL rate cases. Those decisions both concluded that the accrued OPEB liability should be reflected in rate base but that the pension balances should not be recognized in the determination of rate base.

ICC Docket Nos. 11-0280/11-0281, Final Order (January 10, 2012) at 33. Similarly, in 09-0166/09-0167, the Commission disallowed a similar proposal by the Companies to include pension in rate base, noting that :

> The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.

ICC Docket Nos. 09-0166/09-0167, Final Order (January 21, 2010) at 36.

Staff witness Pearce and CUB/City witness Smith both agree with Effron's approach, and similarly removed the Companies' respective net pension assets from rate base, but kept the OPEB liabilities in rate base. *See, generally*, ICC Staff Ex. 14.0 at 3, ICC Staff Schedules 14.1N, 14.1P; CUB/City Ex. 1.0 at 18-22. The People support, and incorporate by reference, Staff's and CUB/City's arguments on this issue.

The People's proposed adjustment reduces PGL's "Retirement Benefits, Net" by $83,706,000 and related ADIT by $33,269,000, resulting in a net reduction to the PGL rate base of $50,347,000. AG Ex. 5.1, Schedule DJE-1P. The adjustment applicable to NS reduces "Retirement Benefits, Net" by $1,841,000 and the related ADIT by $732,000, which results in a net reduction to the NS rate base of $1,109,000. AG Ex. 2.0 at 12-3, AG Ex. 2.1, Schedule DJE-1N. Mr. Effron's adjustments are consistent with the Commission's policy on this issue and the Commission should adopt them.

5. Net Operating Losses

Under Section 9-201 of the Act, a utility filing for a rate increase has the burden of proving its rates are just and reasonable. 220 ILCS 5/9-201. For the first time in this docket, the Companies in their surrebuttal testimony propose a substantial Net Operating Loss ("NOL") for 2012 that significantly increases the Companies' rate base. The adjustment, as discussed *infra*, is unexplained by the Companies' witnesses. NS and PGL failed to provide substantial evidence to demonstrate that the adjustment is necessary or reasonable. The Commission should reject the adjustment because the source and the details surrounding the 2012 NOL is conspicuously absent from the Companies' evidentiary presentation.

NS-PGL witness John Stabile discusses the American Taxpayer Relief Act of 2012, which extended the availability of 50% bonus depreciation into 2013, in his surrebuttal testimony. NS-PGL Ex. 46.0 at 34-35. At the conclusion of that discussion, he briefly notes that because of the bonus depreciation updates in 2013, the Companies are now incurring losses in 2013.[20] Then, without further detail, except a reference to Mr. Hengtgen's surrebuttal discussion, Mr. Stabile, referring to 2012, states, "In addition, based up on the status of year-end closing, the consolidated group is also in an NOL position." *Id.* at 36. No further detail is provided.

NS/PGL witness Hengtgen testified in surrebuttal testimony that he was presenting new stand-alone Net Operating Loss amounts for 2013 *and 2012* at "present rates information." PGL/NS Ex. 43.0 at 26. PGL/NS Ex. 43.2, p. 2 reflects these new ratemaking adjustments. This was the first time the Company suggested or proposed an NOL adjustment for 2012, which is unrelated to the 2013 bonus depreciation extension. Again, the details provided by the Companies for the sudden change in the 2012 NOL status are sparse, to say the least. Mr. Hengtgen's testimony states:

> **B. Net Operating Loss ("NOL")**
>
> **Q. Have the Utilities included an amount for their NOL in rate base?**
>
> A. Yes, Utilities witness Mr. Stabile discusses in his surrebuttal
> testimony the reason for and the amounts of NOLs that the Utilities have included in rate base.
>
> **Q. Have the Utilities reflected the NOLs at present or proposed rates?**
>
> A. The Utilities have reflected the NOLs at present rates in their surrebuttal testimony. However, the Utilities believe it would be appropriate to reflect a reduction to the NOL deferred tax asset based on the tax impacts of the revenue increase that is granted in the final Order in this proceeding.

NS-PGL witness Stabile, at page 36 of NS/PGL Ex. 46.0, provides a limited explanation of the change:

[20] The People do not object to the 2013 NOL recorded in the test year.

> **Q. What is the status of an NOL in the Utilities' surrebuttal filing?**
>
> A. Because the Utilities have included the 2013 bonus depreciation estimates within the update for surrebuttal, they are now incurring losses in 2013. In addition, based upon the status of year end closing, the consolidated group is also in an NOL position.
>
> **Q. Have the Utilities included the deferred income tax effects of the NOL in it (sic) surrebuttal?**
>
> A. Yes. The Utilities have included stand-alone NOL amounts for *2012 and* 2013 in amounts at present rates information. See the surrebuttal testimony of Mr. Hengtgen for further details.

NS/PGL Ex. 46 at 36 (emphasis added). Mr. Stabile's Surrebuttal, as promised by Mr. Hengtgen, in fact do *not* provide the "further details" that he asserted would be forthcoming in the Stabile Surrebuttal testimony that would explain the basis for the NOL, the amounts of the adjustments or how they impact the rate base, or why they waited until the surrebuttal phase of the case to raise the *2012* NOL amounts.

While the Companies suggest that the need to reflect NOL amounts for both 2012 and 2013 is the federal government's extension of bonus depreciation, which occurred after the filing of their Rebuttal testimony, the fact is that the bonus depreciation (prior to the extension that was passed after January 1, 2013 by the U.S. Congress) was in existence throughout 2012. The Companies could have (and should have) estimated potential NOL effects as a result of the bonus depreciation in effect throughout 2012 as an issue either in its Direct or Rebuttal testimony filings. They did not, however.

Mr. Stabile specifically explained in his Rebuttal testimony, "If a utility has more tax deductions than taxable income in a given tax year, it has a tax NOL." NSPGL Ex. 30.0 at 29. Mr. Stabile then further noted in his Rebuttal testimony that "no deferred tax asset exists as of the end of 2012 due to the consolidated groups (sic) income." *Id.* at 27. The Surrebuttal NOL adjustment associated with Congress's extension of the bonus depreciation goes well beyond the 2013 NOL amounts. The Companies' now show an NOL as of the end of 2012, which carries forward into the 2013 test year and affects the calculation of the Companies' revenue requirement to the detriment of ratepayers.

As a result of the Companies' delay in the presentation of this evidence, Staff and Intervenors were foreclosed from responding to this testimony, which significantly affects the Companies' proposed revenue requirements. According to NS-PGL Ex. 43.5P, inclusion of the 2012 NOL increases the PGL test year rate base by $38.597 million. According to NS-PGL Ex. 43.5N, inclusion of the 2012 NOL increases the NS average test year rate base by $2.123 million. If PGL/NS believed it was eligible to recognize an NOL in 2012, that fact could have been raised in an earlier evidentiary filing. Even putting aside the unexplained delay in raising the issue earlier in the case, the Companies have utterly failed to provide a witness to describe the source and cause of the NOL. The paucity of information regarding the proposed adjustment is particularly troubling given that the loss is somehow attributed to "the consolidated group" – presumably a reference to affiliated Integrys companies. NS-PGL Ex. 46.0 at 36.

Under the Commission's rules, utilities must present proposed ratemaking adjustments in the Direct phase of their case. The schedule established by the Administrative Law Judges in this case assumes that each phase of the evidentiary presentation responds to the prior testimony of other parties. Section 200.660 of the Commission's rules provides that a party "may be limited in the presentation of evidence in the proceeding or otherwise restricted in participation, to avoid undue delay and prejudice." (83 Ill. Admin. Code § 200.660).

The Companies' discussion of this new ratemaking proposal also violates Section 287.30 of the Commission's rules, which provides:

Section 287.30 Updates to Future Test Year Data

> a) During the suspension period, the assigned Administrative Law Judge may require or allow the utility to update its schedules and workpapers, if a utility has proposed a future test year, according to the schedule established in the proceeding when evidence has been introduced that a significant and material change affecting the revenue requirement as defined in subsection (c) of this Section has occurred. In establishing this schedule, the Administrative Law Judge shall consider the timing and scope of the updated filing. A utility shall not be allowed or required to submit more than one updated filing, or to submit an updated filing during the final 150 days of the resuspension period. When data are updated, the utility shall also provide updated information for any affected schedules and work papers originally submitted as a requirement of 83 Ill. Adm. Code 285.
>
> b) A determination to require or allow the submission of an update shall include, but not be limited to, the consideration of:
> 1) Whether the changes significantly and materially affect the revenue requirement;
> *2) Whether the changes could have been reflected in the initial tariff filing; and*
> *3) Whether the Illinois Commerce Commission staff and other participants will have an adequate opportunity to review the updated information.*
>
> c) *Examples of "significant and material" changes would include changes since the original filing of tariffs to factors including, but not limited to*:
> 1) Contractual obligations;
> *2) Revenue requirements*;
> 3) Additions or losses of customers served; and
> 4) Governmental requirements or levies, such as tax rates or environmental requirements.
>
> d) Whenever the utility updates projected data in its selected test year, it shall provide a reconciliation of original and updated data and identify and support the changes in its testimony and exhibits.
>
> e) Nothing in this Section shall be construed as a limitation on updates to the rate of return on rate base during the rebuttal phase of the rate proceeding.

83 Ill.Admin.Code Part 287.30. The 2012 NOL, which carries forward into the 2013 test year, could have been presented or raised as a possibility prior to the Utilities Surrebuttal testimony. The Utilities' decision to wait until Surrebuttal to propose this NOL adjustment means that Staff and Intervenors were not permitted to investigate the change through meaningful discovery, let alone comment upon the proposal in testimony.

It should be noted that it appears, based on Staff's Response to the People's Motion to Strike, that Staff witnesses have accepted the Companies' 2012 NOL rate base adjustment, despite the lack of information provided by the Companies explaining the loss and the delay in raising the issue. The Commission should not be satisfied, however, that the 2012 adjustment is necessary simply because of Staff's acquiescence. The People urge the Commission to reject the Companies' eleventh-hour attempt to increase rate base with an unexplained 2012 NOL, attributed to an Integrys affiliate occurrence.

6. Accumulated Deferred Income Taxes

a. Appropriate Methodology to Reflect Change in State Income Tax Rate

It is beyond dispute that Illinois State Income Tax Rates will not remain at the currently higher levels in all future years. State tax rates are scheduled to decline to 7.75% in 2015 and then return to the historical 7.3% in 2025. 35 ILCS 5/Art. 2;[21] see AG Ex. 1.0 at 34. Because most of the Companies' test year income tax expense is deferred, due to accelerated and bonus depreciation and other tax deductions, the future scheduled reduction in income tax rates will result in permanent income tax savings when today's deferred income taxes reverse and become payable. The Companies' calculation of deferred income tax expense for the test year, however, fails to acknowledge this future savings and will overcharge ratepayers. The Companies propose to hide behind a thirty year old Commission Order as the basis to employ a so-called "average rate assumption method" or "ARAM" as the basis to collect higher deferred income taxes today and then only gradually reflect the known and measurable savings in future years.

Boiling down this complex issue to its simplest essence, the Companies are taking income tax deductions today that allow the deferral of taxes that would otherwise be payable at the current, higher rate of 9.5%. (AG Ex. 1.0 at 34). These deductions creates a timing difference where the Companies are booking deferred income taxes at the higher rate, but when the time comes to pay the taxes, the taxes will actually be paid at the lower tax rates scheduled to then be effective.

It must be noted from the outset that this issue was recently addressed by the Commission in the ComEd Formula Rate Docket, (ICC Docket No. 12-0321) and the Ameren Formula Rate Docket (12-0293). In ComEd, the Company proposed, and the Commission approved, a similar position as that proposed by the People in this docket. ComEd explained the change to revenue requirements in its testimony as follows:

> Q. How did the increase in the Illinois income tax rate in 2011 impact the revenue requirement?
> A. The passage of Illinois Senate Bill 2505 on January 13, 2011 increased the previous corporate income tax rate of 7.3% to 9.50% for the years 2011 through 2014, with reductions to 7.75% in 2015 and 7.3% in 2025. This change impacts the revenue requirement in several ways.

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[21] Available at: http://www.ilga.gov/legislation/ilcs/ilcs4.asp?DocName=003500050HArt%2E+2&ActID=577&ChapterID=8&SeqStart=600000&SeqEnd=3100000

> First, the statutory state income tax rate used to calculate the overall total income tax rate on Schedule FR C-4 has been revised to reflect the 9.5% statutory state income tax rate.
>
> Second, as a result of the change in the rate, previously recorded accumulated deferred income tax balances, i.e. balances as of December 31, 2010, were required to be remeasured to reflect the deferred tax balances calculated by applying the new tax rates noted above. The remeasurement of ADIT resulted in a required increase to jurisdictional ADIT as of January 1, 2011 of $13.1 million. Consistent with prior ICC guidance (ICC Docket No. 83-0309, addressing the manner in which deferred tax impacts resulting from tax rate changes should be addressed), this shortfall in ADIT is offset by a regulatory asset and is being amortized prospectively over the remaining life of the underlying assets by applying a weighted-average rate method for future reversals. Amortization of the remeasurement balance was a credit of $1.9 million in 2011.

AG Ex. 1.0 at 35-36, quoting ICC Docket 12-0321, ComEd Ex. 3.0 at 36-38.

Finally, in 2011, ComEd recognized a significant benefit due to the difference between the current income tax rate of 9.50% and the rate at which the related deferred tax expense is recorded. The deferred tax rate is lower because, as described above, the state income tax rate is scheduled to decline in 2015 and again in 2025, which means that some of the deferred taxes recorded in 2011 will reverse in later years when the state income tax rate is scheduled to be lower. This difference in current and deferred tax rates, combined with the fact that during 2011 ComEd had two notable and significant tax deductions (100% bonus depreciation and the expense related to the adoption of the T&D repairs safe harbor methodology) resulted in a 2011 tax benefit of $16,960,000 (jurisdictional), which is included in the tax adjustments shown on Schedule FR C-4.

The Commission accepted ComEd's position on this issue, noting that:

> ComEd submits that, consistent with Commission precedent, this shortfall in ADIT is offset by a regulatory asset and is being amortized prospectively over the remaining life of the underlying asset by applying a weighted average rate for future reversals. Amortization of the re-measurement balance resulted in a credit of $1.9 million in 2011.

ICC Docket 12-0321, Final Order (December 19, 2012) at 33.

Similarly, in the Ameren docket, the Commission adopted the position of ICC Staff and Interveners, including the AG, that the Company must adjust its deferred tax expense to reflect the future tax savings where it would be receiving benefit of lowered state income taxes. ICC Docket No. 12-0293, Final Order (December 12, 2012) at 97. In the ComEd docket, the Company recognized that it was realizing a significant 16.9 million benefit, given the difference between current income tax rate and the rate at which related deferred tax expense is recorded.[22]

Despite the Companies' arguments to the contrary, the accounting principles adopted in ComEd rate case and Ameren rate case apply in this docket. The Companies cite to a Commission's Order from Docket No. 83-0309 that they interpret as applicable in the instant docket. However, the 83-0309 Order does not apply directly to the facts surrounding the temporary increase in Illinois income tax rates in the 2013 test year. The Companies assert that the Average Rate Assumption Method (ARAM) accounting procedures were employed

[22] The adjustment reflecting a $16.9 million tax benefit is quantified at Docket 12-0293, ComEd Ex. 3.2, WP 9, at 2.

in their last set of rate cases (Docket Nos. 11-0280/0281 cons.). While this is factually accurate, a review of the Commission's Order from 11-0280/11-0281 reveals that the alternative approach followed by ComEd and Ameren, and approved by the Commission, was not at issue. *See, generally*, ICC Docket Nos. 11-0280/11-0281 Final Order. Furthermore, the Order in the Companies' prior rate case does not list income tax expense among the contested issues and the only ADIT dispute involved accounting for uncertain tax positions using a 50/50 sharing.

Moreover, the Companies proposed use of ARAM is incorrect in this situation because ARAM applies only to federal income taxes and not to the accounting for State income taxes. As Mr. Brosch explained in his testimony, Internal Revenue Code (IRC) Section 168(e)[23] sets forth "Normalization Requirements" that must be satisfied for a taxpayer to continue to qualify for accelerated methods of tax depreciation and if such requirements are not satisfied, the taxpayer is limited to deduction of only straight-line depreciation on its federal income tax return. AG Ex. 1.0 at 39. These limitations have no applicability whatsoever to the Companies' rate case accounting for State income taxes. ARAM accounting was implemented in 1986 as part of the Tax Reform Act of 1986 (TRA 86) in consideration of federal income tax transition rules to protect utilities from any rapid flow-back by regulators of the then-excessive historically recorded federal ADIT balances, when Federal tax rates were reduced from 46 percent to 35 percent. This is not at issue in this docket. We are not dealing with Federal income taxes or with the flow-back of historically recorded ADIT balances. Instead, the instant issue involves provisions of State ADIT and the Companies' proposed use of ARAM should be disregarded by the Commission in favor of the methods employed for deferred State income taxes in the aforementioned ComEd and Ameren rate proceedings.

As to the applicability of the Commission's order in 83-0309, that docket was an investigation into ratemaking and accounting for excess deferred federal income taxes that required *reversals* of reduced tax rates more than twenty years ago. As with the Companies' proposed use of ARAM, this is not at issue in this docket and the Commission should view its prior order in 83-0309 as inapposite in the instant docket.

In that docket, the Commission ordered

> "that utilities subject to the Commission's jurisdiction over rates which utilize deferred tax accounting shall for ratemaking purposes account for *reversals* resulting from changes in federal and Illinois corporate income tax rates for income taxes deferred in prior years at the weighted average rates at which such deferred income taxes were originally recorded…"

[emphasis added] ICC Docket 83-0309, Final Order (September 18,1985) at 30.[24]

As noted above, the issue in the current docket has been resolved by the Commission in the ComEd and Ameren formula rate proceedings. The current docket has nothing to do with excess deferred income taxes and has nothing to do with reversals of previously recorded ADIT balances. PGL and NSG are able, and should be required, to practice the same liability method of accounting that is employed by ComEd and Ameren for deferred tax provisions based upon the state income tax rates that will be effective in future years when such provisions will reverse.[25]

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[23] Available at http://www.irs.gov/irb/2004-06_IRB/ar09.html.

[24] See AG Exhibit 1.9 for a full copy of this decision, included as Attachment 2 to NS's response to AG 7.03.

[25] A liability method of accounting for Deferred Income Taxes is required under Accounting Standards Codification 840 ("ASC 840"). These requirements were previously referred to as Financial Accounting Standard 109 ("FAS 109") and require for financial reporting purposes that deferred taxes be provided in an amount sufficient to represent the estimated liability that will be paid when book/tax timing differences reverse in future period.

Despite Companies' witness Mr. Stabile's argument to the contrary (NS/PGL Ex. 30.0 at 7), consistent utilization of the liability method of accounting for deferred income taxes (mandated under Generally Accepted Accounting Principles and approved by the Commission for use by ComEd and Ameren) does not cause "distortion." Mr. Stabile provided an illustration in NS-PGL Ex. 30.1 of this supposed distortion. However, the illustration is unreasonably focused upon only a single year of assumed capital additions, as though there is not a continuum of newly acquired or constructed utility assets in every tax year and every potential rate case test year. By focusing only upon a single tax year, Mr. Stabile is able to argue that "Customers in 2013 would pay approximately $2.1 million less for the use of those assets, as compared to customers in 2014." NS/PGL Ex. 30.0 at 7. The reality, however, is that "customers in 2014" would realize comparable deferred income tax expense savings due to the Companies' expected acquisition and construction of new tax-deductible assets in 2014, and in every year thereafter.

In addition, the People's proposed adjustment does not "flow through" a non-repeating benefit that will subsequently increase the carrying cost of that asset, as Mr. Stabile argues. NS/PGL Ex. 30.0 at 7; NS/PGL Ex. 30.1. As noted by Mr. Brosch, the actual impact of using the liability method of accounting is to recognize *in each and every year* that income taxes being deferred on newly added assets should be quantified based upon the statutory tax rates that will be effective when such deferred taxes later become currently payable. As seen in the instant docket, with the scheduled reductions in the Illinois State Income Tax rates, deferral of taxes during period of higher tax rates that will actually be paid in distant future years, when tax rates are lower, represent very real and permanent income tax savings that should not be denied to ratepayers. The Companies' proposed use of ARAM accounting improperly complicates accounting and ratemaking for the temporarily higher State tax rates and charges customers a higher deferred income tax expense today than is expected to actually be paid in the future, when book/tax timing differences originating today will reverse.

Mr. Stabile's arguments on increased carrying costs are potentially misleading because they inherently assume that when customers should be indifferent to paying higher rates sooner versus later. The lower deferred income tax balances and incremental higher rate base under the AG/CUB method (and that approved in the ComEd and Ameren dockets) represent an accounting for the simple fact that ratepayers are not being forced to pay excessive deferred income tax expenses today when the flawed ARAM approach is rejected. The lower deferred tax balances and correspondingly larger future rate base amounts simply and consistently account for the time value of money during those years that the Companies are not receiving the larger tax deferral benefits Mr. Stabile would instead like to collect from customers under the ARAM method he supports.

Finally, the AG and CUB/City proposed adjustments are not "flow through" adjustments. Rather, they serve only to correct test year deferred tax expense calculations to account for differences between current and future statutory tax rates, using the GAAP-required liability method of tax normalization accounting, with no flowing through of the tax deferrals arising from annual additions to utility plant. There is no uncertainty created by using the AG/CUB proposed method of accounting. For ratemaking purposes, the deferred income tax expenses should be recorded at the income tax rates expected to be effective when book/tax timing differences reverse in future years under the liability method. If the legislature acts to again change income tax rates, a re-measurement of required deferred income taxes would again occur and adjustments to deferred income tax expense would result from the changed tax rates in future rate cases. The Companies should have no problem recovering income tax expenses that are recorded in future test years pursuant to applicable accounting rules, even if the result is a higher revenue requirement in rate cases.

b. Repairs Deduction Related to AMRP projects

As the Commission recently stated, "Generally, ADIT quantifies the income taxes that are deferred when the tax law provides for deductions with respect to an item, in a year other than the year in which the item is treated as an expense for financial reporting purposes. For regulated entities, ADIT is treated as a non-cost source of capital that reduces rate base." ICC Docket 11-0721, Order at 56, citing *Ameren Illinois Co. v. Ill. Commerce Comm'n*, 2012 IL APP (4th) 100962 at 5, 2012 Ill.App.3d LEXIS 175 (4th Dist. 2012). As the Commission has noted in several previous orders, until the Companies' actually pay their deferred tax liabilities to the relevant taxing authorities, they represent non-investor supplied funds available to the Companies. In this docket, the Companies are not properly recognizing the appropriate balances of ADIT in their determination of the test year rate bases. The Commission should reject the Companies' deviation from the standard treatment of ADITs and reduce rate base accordingly to reflect non-investor capital available as a result of the Companies' repairs deductions and elimination of the unexplained and undocumented 2012 net operating loss.

The Companies' rebuttal testimony unveiled an unexpected reversal of course that will cost ratepayers dearly: the Companies no longer believe that AMRP costs qualify under safe harbor guidance as deductible tax repairs that would reduce rate base. NS/PGL Ex. 46.0 at 30. The net effect of this reversal is a decrease in ADIT of over $47 million as of the end of 2013, resulting in an over $32 million increase in its average test year rate base[26] – an increase that falls squarely on the shoulders of ratepayers. Although PGL claims that plant costs related to AMRP could no longer be treated as tax repairs, PGL has failed to justify its reversal on this issue.

In PGL's direct case, the Company assumed that its AMRP should be treated as any other distribution facility project for the purposes of repairs deductions. NS/PGL Ex. 30.0 at 17. In rebuttal testimony, however, Company witness Stabile testified that the Company had reviewed the guidance provided in Internal Revenue Service (IRS) Revenue Procedure 2011-43, but in the absence of a bright line rule, the Company felt it was no longer reasonable to classify AMRP expenses as repairs for tax purposes. Id. at 17-18.

PGL's premises for changing their treatment of AMRP costs appear to be quite thin. At the time of their direct testimony, some of the 2012 and 2013 AMRP plant costs were treated as tax repairs; at the time of rebuttal testimony, it was assumed none of those costs would qualify as tax repairs. Peoples Gas has not established that the assumptions in its rebuttal testimony are more valid than the treatment adopted in its direct testimony. Unless Peoples Gas can better substantiate why the tax treatment of the AMRP costs in its direct testimony was inappropriate, the determination of the test year balance of ADIT and rate base should continue to reflect that treatment.

The Company notes that its original position was no longer reasonable because of a change to its interpretation of IRS Revenue Procedure 2011-43. AG Ex. 5.2 at 1-3. Procedure 2011-43 outlines which plant repairs would qualify as repairs for tax income deferral for electric utilities. In particular, PGL cited to the issuance of IRS Revenue Procedure 2012-39, which delayed the implementation of Procedure 2011-43 by one year. However, AG witness Effron's interpretation of Procedure 2012-39 is that the new Procedure only delayed implementation of certain *limitations* in 2011-43, it did not impose new restrictive guidelines as to what would qualify as a tax repair. AG Ex. 5.0 at 5 (emphasis added).

[26] AG Ex. 5.0 at 4.

In its response to AG Data Request 15.09, PGL also noted that the lack of IRS guidelines specifically applicable to gas utilities. AG Ex. 5.2 at 3-4. Other than this thin reason, PGL has not explained why Procedure 2012-39 would cause it to believe expenditures that it previously believed would qualify as tax repairs no longer qualify. Also in the response to AG Data Request 15.09, PGL noted the "evolution of the public record in the instant case from July 31, 2012 to the present" related to the AMRP as a changed circumstance. *Id.* at 4. Aside from this obtuse description, the Company cites to nothing in the public record of the instant docket that somehow changed the basic nature of the AMRP and it cites to no specific changes to AMRP that now cause AMRP expenditures to not qualify as tax repairs, whereas they had previously qualified. Finally, PGL responded that the IRS has not released specific guidance providing the gas transmission and distribution industry ("Gas T&D") with a safe harbor method of accounting for tax repairs. *Id.* at 4. While PGL may have anticipated that guidance would have been issued by now, the fact that the IRS has not released such guidance does not amount to a change in facts or circumstances and it certainly does not amount to a reason to saddle ratepayers with providing the Company with a cost-free loan via increased rates. The People's proposed adjustment is fair and reasonable and is not overcome by the Company's protestations to the contrary.

Certain of PGL's claims are simply implausible. For example, PGL asserts that did not start looking at how the AMRP would be treated for tax purposes until October 2012.[27] Given the size of the AMRP program and the length of time that the program has been either under consideration or in place, it is difficult to understand how IBS Tax would not start looking at how AMRP would be viewed until October 2012. This is simply not a plausible excuse for the Company's change in the treatment of AMRP costs and should be rejected by the Commission.

PGL also now claims that AMRP could be caught under two exceptions: per se capital expenditures (which cannot be treated as tax repairs under any circumstances) and the aggregation rule (aggregation of expenditures to determine whether they exceed 10% of a unit of property – which would disqualify them from tax repair deductions). AG Ex. 5.2 at 6. However, these exceptions to the safe harbor are not new or novel. They existed in the Procedure that was in place before PGL filed its direct case.

AG witness Mr. Effron also noted that PGL's position is not the most common or preferred position in the utility industry – noting that more than 60% of utilities have filed method changes for tax repairs. AG Ex. 5.0 at 8. In Mr. Effron's experience in a rate case in another state, Rhode Island's gas utility, Narragansett Electric Company, replaced a series of gas mains on an accelerated basis and concluded that almost half of its repairs would qualify as tax repairs.

Given the paper-thin justifications provided by the Company to explain its position, the Commission should adopt the AG position.

c. Bonus Depreciation

The People do not object to the Companies' proposed $47,235,373 (PGL) and $3,250,333 (NS) adjustments to ADIT and rate base as a result of claiming bonus depreciation for 2012 and 2013 as outlined in Mr. Stabile's surrebuttal testimony. NS/PGL Ex. 46.0 at 34-36.

d. Derivative Adjustments from Contested Adjustments

D. Accumulated Depreciation (Uncontested Except

[27] "IBS Tax reviewed the Utilities' testimony related to estimates of capital expenditures related to gas main replacements. Subsequent to that review, multiple data requests by Staff and intervenors were made seeking specifics related to the Utilities' estimated AMRP expenditures. Based on this analysis, IBS Tax started looking at how AMRP would be viewed." AG Ex. 5.2 at 7.

for Derivative Adjustments from Contested Adjustments)

V. OPERATING EXPENSES

A. Overview/Summary/Totals

1. North Shore

2. Peoples Gas

B. Potentially Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Administrative & General

a. Interest Expense on Budget Payment Plan

b. Interest Expense on Customer Deposits

c. Lobbying expenses

d. Social and Service Club Dues

e. Executive Perquisites

f. Consulting Expense – SIG Consulting

g. Employee/Retiree Perquisites – Awassa Lodge

h. Update to Pension and Benefits

i. Updated IBS Return on Investment

j. Costs to Achieve Amortization

2. Uncollectible Account Expense Included in Base Rates

3. Depreciation Expense

a. WAM System

b. CNG Plant

4. Income Tax Expense – Changes in Interest Expense on Debt Financing

5. Revenues

a. Sales and Revenue Adjustment by Service Classification

6. Interest Synchronization (methodology on derivative adjustments)

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Incentive Compensation (Falls in Multiple Categories of O&M)

The Commission has permitted the recovery of incentive compensation costs in rates only when it is demonstrated that such compensation operates to provide identifiable benefits to the utility's customers. This policy reflects the Commission's reasoned approach to the incentive compensation issue, which was upheld by the Illinois Appellate Court in *Commonwealth Edison Co. v. Illinois Commerce Comm'n.*, 398 Ill.App.3d 510, 924 N.E.2d 1065 (2d Dist 2009), reh. den. April 6, 2010.

Initial test year incentive compensation expenses total about $11.5 million for PGL and about $1.8 million for NSG in the projected test year. These expense amounts relate primarily to the estimated awards under the 2013 Annual Incentive Plan, with smaller amounts attributable to estimated expenses for Stock Options, Performance Shares and Restricted Stock. Additional incentive plan cost amounts are proposed for rate base inclusion when such labor-related amounts are capitalized in support of plant construction activities. The estimated 2013 amount of incentives charged to construction is $1.2 million for PGL and $0.1 million for NSG. AG Ex. 1.0 at 27.[28]

[28] The incentive compensation amounts forecasted by the Companies in the test year were developed based upon the terms of the incentive compensation plans in effect for performance during the calendar year 2012, given that the calendar year 2013 incentive compensation plans will not be approved until early 2013, and those plans

AG witness Brosch sponsored three adjustments to the test year proposed incentive compensation amounts. Two specific adjustments to eliminate the expenses forecasted for stock-based Executive Incentive Compensation Plan and the Omnibus Incentive Compensation (equity/stock) Plan were not disputed by the Companies. NS-PGL Ex. 29.0 at 2. However, a 50% disallowance Mr. Brosch proposed for the Companies' Non-Executive Incentive Compensation Plan, also proposed by CUB witness Ralph Smith, remains at issue. Mr. Brosch revised his calculations of the AG-proposed 50 percent disallowance of Non-executive Annual Incentive Expense, after reflecting the PGL and NSG disallowances accepted in the Companies' rebuttal evidence, within Schedule C-5 appearing in AG Exhibits 4.1 and 4.2 for PGL and NSG, respectively.

As described in NS-PGL Ex. 9.1, the primary drivers of incentive payouts under the Non-executive Annual Incentive Plan are weighted among several categories that vary slightly for persons directly employed by PGL or NSG, persons employed by IBS, and employees of other Integrys business units. For PGL and NSG, the targeted performance areas are:

- Adjusted O&M Expenses (combined all utilities) 50%
- Employee Safety (OSHA accident rates) 15%
- Customer Satisfaction Surveys (by utility) 15%
- Leak Reduction (PGL class II / NSG total leaks) 10%
- Reduction in Damages by Company Crews 5%
- Reduction in Damages by 2^{nd},3^{rd} Party Crews 5%

The Annual Incentive plan is based upon targeted performance levels in each area, with actual performance measured and compared to targets after each calendar year-end, to calculate cash incentive amounts payable to employees in March. *See* NS-PGL Ex. 9.1. It is unclear whether the Companies' employees will earn incentive compensation under the Adjusted O&M Expenses metric if the Company actually spends the amounts that are projected in the test year for non-fuel Adjusted O&M expense, because the performance parameters for the actual 2013 Annual Incentive plan have not yet been developed and approved. AG Ex. 1.0 at 29. Additionally, since the Non-executive Annual Incentive Plan combines the O&M expenses of all Integrys utility businesses to calculate awards, it is possible that PGL and NSG expenses could exceed targeted levels and incentives could still be paid if expense savings at other affiliated utilities outside of Illinois achieve sufficient expense savings. AG Ex. 1.0 at 31.

AG witness Brosch carefully reviewed the terms of the plan, along with relevant data request responses, and concluded that ratepayers should not be responsible for the expenses for the 50% of disputed incentive plan expenses, even if it is assumed the Annual Incentive plan will be effective at promoting and achieving reductions in test year expenses. He explained that any achieved future O&M savings, relative to asserted test year levels of expenses, will be retained for the sole benefit of shareholders because test year expense amounts for ratemaking purposes are based upon forecasted expense amounts rather than upon actual expense levels that drive incentive plan payouts. Indeed, the Companies have failed to identify any reductions included in their test year O&M estimates that represent specific cost savings or assumed productivity offsets to forecasted inflation and wage rate escalations that will result from incentives being paid to employees. *Id.*

Absent a calibration of specific O&M reductions to the incentive compensation metrics in the Company's test year expense forecasts, the Commission should assume that the

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are expected to be substantially identical with the same metrics and weightings as the 2012 plan documented in NS-PGL Ex. 9.1, sponsored by the Companies' witness, Noreen Cleary. AG Ex. 1.0 at 27.

Annual Incentive plan O&M component is self-funded out of expense savings that are being retained for the sole benefit of shareholders. The alternative assumption would be that expense savings are not being achieved at levels sufficient to "pay for" annual incentives to employees, in which instance the O&M components of the Annual Incentive plan is dysfunctional and should be discontinued by the Companies. *Id.* at 29-30.

The Companies attempt to explain the linkage between achieved O&M savings and rate recovery of incentive compensation consists primarily of suggestions that estimated test year expenses and the corresponding proposed revenue requirements would likely have been higher absent the incentive compensation program. Nevertheless, the Companies admit that "it is not possible, however, to show a direct link to particular dollars in specific line items of the annual O&M budgets that have been reduced or controlled…as a result of the O&M cost control metric." AG Ex. 1.0 at 30, citing NS-PGL response to AG data request 7.36. AG witness Brosch specifically rejected the Companies' statement that "It is commonly understood that when costs are reduced or controlled in one year, that reduction or control carries through to the basis used in planning the following years' budgets." AG Ex. 1.0 at 31 (citing NS-PGL response to AG data request 7.36). He noted that the much higher O&M expenses being proposed by the Companies in the test year in these dockets reflect no apparent cost controls either historically or assumed to be exercised in the future. Given (1) the Companies' burden of proof under Section 9-201 of the Act and (2) the absence of any direct link between forecasted test year adjusted O&M and the targeted O&M within incentive compensation plans, the Commission should preclude rate recovery of such incentive compensation amounts.

In fact, the Companies will never be able to demonstrate an observable direct link between forecasted PGL and NSG test year adjusted O&M expenses (i.e., the utility customer benefit) and the amounts that drive payouts under the Companies' Annual Incentive plan as currently constructed because the targeted O&M expenses used to administer the plan consists of a combined "Utility and IBS FERC-based non-fuel O&M" amount from the consolidated budgets of *all* Integrys utility subsidiaries, along with IBS expenses. This large pool of O&M expenses that drives incentive payouts is influenced by O&M performance of multiple Integrys businesses beyond the regulated utilities. Accordingly, not only is the O&M parameter of the plan not tied to expenses included in 2013 rate case forecasted O&M, the payouts under this plan are ultimately driven by a much larger universe of utility operations than just these two Illinois utilities. As such, the Companies have failed to demonstrate any kind of identifiable PGL/NS customer benefit associated with the O&M expense element of the plan that may be cultivated by the Integrys utilities in Illinois for ultimate crediting to PGL and NSG ratepayers.

AG Exhibit 4.1 and Exhibit 4.2 at Schedule C-5 contain calculations showing the disallowance of 50 percent of the Annual Incentive Plan expenses that have been included in the Companies test year O&M expense forecast after recognizing the Companies' concessions regarding the other incentive plans in rebuttal evidence. It should be noted that the other 50 percent portion of Non-executive Annual Incentive plan expenses that are driven by employee safety, customer satisfaction and leak response, are not being disallowed at Schedule C-5 and are allowed to remain in test year projected expenses based upon an assumption that these plan parameters are cost effective, provide a direct customer benefit and will be met in the test year.

It should be noted, too, that there is no inconsistency between disallowing these particular incentive compensation plan costs and the AG-proposed Productivity Adjustment to offset assumed inflation and wage rate escalation assumptions that were used by the Companies in forecasting test year expenses. As noted by Mr. Brosch, the large amounts of Annual Incentive Compensation that were initially included in the Companies' asserted revenue requirement implied a need for much larger productivity gains than the minimum one-half percent per year allowance recommended in testimony. For example, the 50 percent of Annual Incentive costs estimated for PGL that are driven by O&M cost savings achievement would add more than $5 million to annual expenses ($10.2 million in total expense times 50 percent).[29] Assuming that the incentive paid should represent only a reasonable fraction, perhaps no more than half of the actual O&M savings experienced by the Company, expense savings of $10 million or more should be expected in each year that PGL pays out such large incentives. Annual savings of $10 million would represent nearly three percent of PGL's proposed Total O&M Expenses of $346 million[30] in the test year. This comparison implies that Mr. Brosch's one-half percent annual assumed productivity reduction to O&M is conservative in light of (1) the annual achievable savings that the Companies themselves believe are within management control and (2) the fact that the Companies should be able to "pay for" the O&M element of Annual Incentive Plan costs out of retained O&M savings that are not being fully reflected in test year expense estimates. AG Ex. 1.0 at 33.

In response to the conservative AG-proposed Non-executive incentive compensation plan, NS-PGL witness Cleary argues that Mr. Brosch's adjustment is rooted in an objection to the Companies' selection of a future test year. NS-PGL Ex. 29.0 at 12-13. But that argument misses the mark. Clearly, the Company is permitted under test year rules to select a future test year. *See* 83 Ill.Admin.Code Part 287.20. But no Commission rule precludes the Companies from recognizing and including in a future test year forecast the particular savings that must be attributed to an incentive compensation plan for it to be deemed cost effective in controlling O&M expenses. If incentive compensation plans are believed by the Companies to be effective and incrementally reducing expenses in each year that such incentives are paid, both the cost of the incentives and the benefits produced by the plan, i.e. the corresponding expense savings, must be included within test year forecasts.

The AG-proposed adjustment is rooted in the clear law established in the aforementioned *ComEd* case, and the related principle that if incentive compensation costs are being allowed based upon the premise that cost-control metrics within the incentive plan are cost-effective, one of two outcomes should be required whenever a forecasted test year is employed. Either the Companies should be able to demonstrate with specificity that forecasted test year expenses have been directly reduced incrementally for the expected amounts of future cost savings that will be induced by 2013 payments of incentive compensation, or, alternatively, if such direct reductions for incentive plan driven O&M savings have not been demonstrated to exist within the rate case expense forecast, the Companies' shareholders should bear the cost of the cost-control portion of incentive compensation, because they alone will benefit when and if such savings occur in 2013. Shareholders alone will benefit because the relevant O&M savings are not reflected in rate case forecasted O&M.

At page 13 of her rebuttal testimony, Ms. Cleary refers to a 2005 ComEd rate case where the Commission is said to have concluded, "…that expenses for incentive compensation metrics that encourage O&M cost control benefit customers because '[l]owering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases'." NS-PGL Ex. 29.0 at 13. But what is missing from this analysis is an acknowledgment that in 2005 ComEd's rates were being set based upon historically incurred costs, which would automatically include any and all experienced cost savings that were caused by the recorded amounts of incentive compensation costs in the

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[29] AG Ex. 1.0 at 33, citing PGL response to data request JMO 15.01, Attachment 1 indicates test year Annual Incentive Plan expenses of $10,207,920 are included in test year forecasted expenses.

[30] See NS-PGL Ex. 18.1P , page 1 of 1, column E, line 24.

historical test year. In such an environment, ratepayers are assured of participation in recorded expense savings resulting from cost-effective incentive compensation plans that result in actual cost reductions. Additionally, because ComEd's expenses were not based upon a forecast, there was no need to verify that incentive plan-driven expense savings were not being ignored in developing the forecast. AG Ex. 4.0 at 32.

The instant case is quite different than Ms. Cleary's example, however. Here a forecasted test year is being employed. The O&M amounts in the test year forecasts of each utility are estimated, such that there is no assurance that any future expense savings that may be realized because of incentive compensation-driven cost controls will ever be shared with ratepayers. Utility management has every incentive to pessimistically forecast its costs in the forecasted test year and then keep for shareholders any actual expense savings that may later appear within recorded financial results. *Id.*

With respect to the Companies inability to show specific 2013 test year O&M savings, Ms. Cleary simply observes in rebuttal that, "….after the implementation of the O&M cost control metric, both Peoples Gas and North Shore were able to lower their levels of Total Non-fuel O&M Expense Adjusted below the goals set in the incentive plan for 2011, as well as versus the previous year's levels for such costs." NS-PGL Ex. 29.0 at 14. The Commission is left to imagine that if expense savings were actually achieved in 2011 because of the existence of incentive compensation programs, there must be savings embedded in the 2013 test year forecasts as a result. Such an extrapolation misses the point that PGL and NSG expect to pay and recover incentive compensation every year for ratemaking purposes, and such annual recovery requires incremental *new* O&M savings in 2012, the 2013 test year and every subsequent year for such incentive payments to be judged cost-effective. Presumably her point is that since cost reductions were believed to have been achieved in 2011, the absence of utility-specific cost control metrics for the plan in later years and in the 2013 test year cannot reasonably be challenged. This is a hollow argument that should be rejected.

Ms. Cleary offered revisions to the annual expense savings percentages that would be required to pay for incentive compensation plan costs, in relation to the AG's proposed 0.5 percent annual productivity offset. *Id.* In his Direct Testimony, Mr. Brosch indicated that annual expense savings of about 3% of O&M should be expected each year to be sure that the O&M cost control metric within the Companies' incentive compensation plans does not cost more in compensation to employees than the expense savings that are produced. Given the Companies' consent in rebuttal to disallow the Executive Incentive Plan costs, and also assuming no expense reductions should be demanded by ratepayers for a plan that it is now treated as shareholder funded, Ms. Cleary argues that only a 1.66% expense savings should be required in test year O&M savings to pay for the incentive compensation plan cost controls now being requested.

The Companies, however, have not demonstrated that any future test year expense savings expected to be caused by 2013 incentive payments have been forecasted, which is why O&M incentives should not be recovered from customers. With regard to the AG's proposed productivity offset of 0.5 percent per year, incentive plan-driven annual expense savings of 1.66% still represent more than three times the 0.5% productivity offset that is being recommended in the AG revenue requirement presentation. Mr. Brosch's made clear, as noted in the Productivity Adjustment section of this Brief, that the AG-proposed productivity adjustment incorporates the decreased test year amount of incentive compensation.

For all of the reasons cited above, the AG-proposed 50% reduction to the Companies' Non-executive incentive compensation plan should be adopted.

2. Wage Increase Corrections

3. Non-union Base Wages (Falls in Multiple Categories of O&M)

4. Vacancy Adjustment (Falls in Multiple Categories of O&M)

AG witness Mr. Brosch proposed a Vacancy Rate Labor Adjustment to O&M expenses in the amount of $7,550,000 (PGL) and $837,000 (NS). AG Ex. 4.1, sched. C-2; AG Ex. 4.2, sched. C-2. The Commission should adopt this proposal because, as explained in greater detail below, it presents a more reasonable and more realistic projection of the Companies' actual test year spending for labor, benefits and payroll tax expenses, based upon the known and measurable reality that turnover within the workforce and unavoidable delays in the process of filling positions creates a normal and ongoing level of vacancies in actual staffing levels. AG Ex. 1.0 at 18. The People submit that the proposed adjustment is a conservative and necessary offset to the massive and largely unsupported increase in staffing and labor-related expense that is proposed for PGL in the test year. If a normal level of employee vacancies is not injected into the Companies' vastly increased staffing and labor and benefit expense forecasts, ratepayers will clearly be burdened with overstated expense estimates.

An analysis conducted by Mr. Brosch revealed that the Companies have overstated the number of employees they expect to add in the test year and then unrealistically presume that no vacancies will occur at the higher proposed staffing levels. PGL predicts it will employ 1,357 employees in all months of the test year and NS predicts employing a constant level of 171 positions. PGL/NSG Exhibit 5.1 at 8, Sched. G-5. For PGL, this forecasted staffing level stands in stark contrast to its average summer actual 2012 level of only 1,223 employees. *See* AG Ex. 1.0 at footnote 13. Of primary concern to the AG is that the Companies started with their *actual* staffing levels as of the time of preparation of the forecast and simply added personnel where they *believed* expansion was needed. This is problematic, particularly because the Companies are projecting what Mr. Brosch deemed a "highly unusual" 24% rate of growth to staffing in merely two years. AG Ex. 1.0 at 16. Mr. Brosch tested the reasonableness of these projections by evaluating whether a similar proposed level of staffing was achieved in calendar year 2012. After a review of the available data, Mr. Brosch found a burst of hiring that plateaued with staffing levels at 1,223 positions, which is well below PGL's projections of 1,357 positions. AG Ex. 1.0 at 18.

It is important to remember that actual hiring decisions are largely within the control of utility management. It is quite possible for a utility to forecast a level of authorized positions and then decide to not fill, or delay the backfilling, of some of the forecasted positions. Vacant positions are a reality of business operations and are likely to exist for whatever length of time it takes in order to appropriately recruit, interview, offer, test and ultimately fill or backfill the position. Given these realities, it is unreasonable to anticipate anything other than a "normal" level of vacancies among approved staff positions. The Companies, however, unrealistically assume that every forecasted new and existing authorized employee position will be filled by an active employee throughout the test year. PGL Schedule G-5, NS Schedule G-5. Given the impossibilities of achieving and maintaining full staffing of every position, the Companies' position that there will be no vacancies among its projected higher authorized staff count is unreliable and unrealistic and should be disregarded by the Commission.

Moreover, the Companies' increased staffing level projections lack substance and have not been justified. In particular, PGL projects adding 263 employees to its AMRP and to implement a company-wide reorganization. This proposed dramatic staffing level increase becomes problematic for ratepayers because higher labor-related expenses mean higher gas rates and the Companies have simply not justified these higher expenses. Despite numerous requests during the discovery phase of this docket, the Companies did little to actually justify the need for proposed staffing level increases. PGL responded with little more that high level analyses and incremental labor demand estimates. *See* AG Ex. 1.5. Moreover, the Companies submitted no direct testimony and little documentation to support a 24% burst in PGL staffing. If the Companies truly need to employ additional workers in order to deliver safe, reliable, and effective service, it is realistic to expect some quantitative showing of why the proposed number of added personnel is prudently needed. It is as simple as that. However, the failure of the Companies to justify proposed staff count increases leaves the Commission with no alternative than to either reject the Companies' labor cost increase projection in total, or to adopt the conservatively quantified offset for a reasonable estimate of ongoing employee vacancies as proposed by AG witness Brosch.

To rectify the imbalance reflected in the Companies' unreasonable staffing increases and full employment (no vacancies) test year assumptions, Mr. Brosch proposed an adjustment that accounts for the reality that no employee can avoid normal employee turnover and the resulting temporarily vacant positions that result from such turnover. After careful analysis, Mr. Brosch proposed an adjustment for each utility that reflects an historically calculated "average vacancy factor" for Company and IBS employees based on *actual* compared to *authorized numbers* of employees throughout 2012. Mr. Brosch calculated the proposed vacancy factors by using the Companies' own historical data. He simply divided the number of authorized but unfilled employee positions during January through September 2012 by the total number of authorized positions in each month.[31] Notably, Mr. Brosch's analysis accepted the premise that the Companies' forecasted targeted numbers of employees will actually be needed to run the business in the test year, in the absence of any real proof of such need, while offsetting forecasted labor costs only to recognize the reality that actual staffing levels will not fully achieve targeted staffing levels. AG Ex. 1.0 at 20.

The Companies argue that the vacancy rate adjustment proposed by Mr. Brosch is based upon "snapshots" of employee counts that do not reflect existing and future additions to employee counts. NS/PGL Ex. 4.0 at 14. Notably absent from the Companies' response is any proof that its proposed future additions to employee counts or the many existing positions will remain filled throughout the 2013 test year without any occasional vacant positions arising from normal workforce turnover. PGL also attempts to explain away the reality of employee turnover and vacancies by citing to its training school. NS/PGL 28.0 at 14. However, as Mr. Brosch testified, "The need to create a 'school' to train and hire new employees is indicative of the challenges associated with attracting and retaining qualified staff even in periods of relatively high unemployment." AG Ex. 4.0 at 17. Additionally, the fact that, at the time that the Companies filed their rebuttal testimony, NS was two positions below its targeted staffing levels should not influence the Commission. This is merely another of the Companies' "snapshots" that fails to account for unplanned vacancies throughout the year. Failing to properly account for these inevitable vacancies will cause Illinois ratepayers to overpay for salaries and benefits for employees that, at various points throughout the year, simply do not exist.

Mr. Brosch's vacancy rate adjustment is reflective of business realities where authorized positions are not always filled and should be considered by the Commission in determining actual test year labor-related expenses because Mr. Brosch based his calculations upon average levels of employee vacancies that actually existed during the first nine months

[31] In September 2012, the number of authorized positions was 1,294 (PGL) and 170 (NS) and the number of filled positions was 1,222 (PGL) and 169 (NS). AG Ex. 1.6 at 7, 25.

of 2012, the most recent data available for analysis. He compared the actual number of positions actually filled in each month with the Companies' planned and authorized positions, to determine the vacancy percentage present within the utilities. This distinction is important because it inject realistic staffing and labor cost assumptions into the forecast, in placed of the Companies' overly optimistic and unreasonable expectation that the Companies may magically avoid the unavoidable and continuous turnover and periodic vacancies experienced by every large employer. AG Ex. 4.0 at 16. Any large business organization will be functionally unable to fully and precisely anticipate all retirements, terminations, new hiring, and training. The Companies position would require the Commission to assume that these businesses are different from other utilities, and are somehow able to anticipate each and every termination of employment and have a replacement employee hired and ready to start on the very next day. This does not reflect the reality of the working world where positions may remain unfilled for weeks or months in order to find a suitable replacement – or even to leave the position unfilled to avoid salary costs or costs associated with recruiting and training. AG Ex. 4.0 at 16.

Other state's Commissions have adopted similar employee vacancy factors to reduce forecasted labor and benefit expenses. As an example, the Hawaiian Commission, over the last several years, approved and adopted vacancy factors ranging from 2.68% to 7.31%. AG Ex. 4.0 at 19. It is essential that the Peoples vacancy rate adjustment be adopted to improve the credibility of the Companies' largely unsupported test year forecasts of labor-related expenses driven higher by proposed staffing increases, by injecting a conservatively quantified offset for vacant positions that certainly will be experienced among the authorized staffing levels that are unrealistically assumed to be 100 percent filled and paid throughout the test year.

Notably, CUB/City Witness Mr. Smith also proposes a vacancy adjustment to adjust the Companies' overstated labor cost projections. CUB/City Ex. 1.0 at 47-55; CUB/City Ex. 2.0 at 22-25. Although Staff witness Mr. Ostrander did not adopt the AG's adjustment, it is important to note that Mr. Ostrander conducted no independent analysis of employee vacancy rates. Tr. at 247. The AG proposal was conservatively crafted, reflective of the business realities, and should be adopted by the Commission.

5. Distribution O&M

a. Plastic Pipefitting Remediation Project

b. Legacy Sewer Lateral Cross Bore Program

In supplemental direct testimony filed by Mr. Hoops, the Companies requested that ratepayers be charged an additional $5.7 million (PGL) and $2.6 million (NS)[32] annually for the estimated costs of the Companies' new "cross-bore" project: a project that plans on hiring contractors to send cameras through 91,000 PGL and 52,000 NS service pipes at points where there is some potential cross-over with sewer lines and laterals to find out whether a gas main, line, or segment had been drilled through. NS/PGL Ex. 28.0 at 6. Each camera inspection is expected to cost ratepayers $250 and up to $500 if the camera's view is obstructed and excavation is required. *Id.* at 6-7. The estimated costs would be higher if and when the inspections require additional permitting or remediation. *Id.* Because the Companies have not fully developed, explained or justified their plans for spending this ratepayer-supplied money, or actually commenced any work to date, the People urge the Commission to reject these speculative additional multi-million dollar expense allowances.

[32] AG Ex. 4.1, sched. C-4; AG Ex. 4.2, sched. C-4.

After careful analysis, AG witness Brosch recommended rejecting the estimated new expenses related to this cross-bore project based upon the Companies' failure to meet their burden of justifying the expenses. AG Ex. 1.0 at 47. Two issues are particularly troubling to the People. First, work has not even begun on the program, even though the concerns associated with potential cross-bore risks have existed for many years. Second, the timing of the proposed new investigation program and the associated expenses are overly discretionary and there is no evidence of a commitment to actually spend at forecasted levels.

In the Companies' direct case, they provided little explanation of assumptions, calculations, or other support for the expenses on this project. As this docket progressed, the Companies routinely and continually failed to satisfactorily justify these additions to O&M expenses. While this alone demonstrates the Companies' lack of commitment to completing (or even starting) this project, the record evidence speaks volumes about the project. The Companies assert that PGL has been "investigating" cross-bores as part of the AMRP program and that the project should begin in the first quarter of 2013. NS-PGL Ex. 44.0 at 5. However, the record evidence in this case demonstrates that, as of February 2013, only one out of eight positions alleged by the Companies to be necessary to completing this project have been filled. AG Ex. 4.0 at 50, AG Cross Ex. 12. Even more distressing is that, as of the date of the evidentiary hearing in this docket, the Companies had not issued requests for bids. Tr. at 375-6. Forecasts were created without the benefit of having a bid or work plan in hand, further demonstrating the speculative nature of the potential addition to O&M expenses. AG Cross Ex. 11.

The Commission should require the Companies to provide more specific work plans that will detail the hiring of employees, contractual commitments to perform work, and detailed expenses for the project. Until this level of detail can be provided, the Commission should reject the highly speculative $5.7 million (PGL) and $2.6 million (NS) additions to expenses. Quite simply, it is unclear at this point whether the Companies are serious about starting or completing this project in a timely manner or whether activities and costs in other parts of the business could be shifted to cover cross bore investigation and remediation work without adding additional amounts to projected test year expense estimates. The ratepayers of Illinois should not be on the hook for the expenses associated with such a speculative project with an unclear starting or ending date.

c. New Chicago Department of Transportation Regulations

AG witness Michael Brosch made an appropriate adjustment to test year O&M expenses that reduces the Company's attempt to wring $13.9 million from ratepayers as expenses for what PGL characterized as,"known and measureable changes to Peoples Gas' cost of service due to recent changes to the Chicago Department of Transportation ("CDOT") Regulations" related to construction and repairs within city limits. NS/PGL Ex. 20.0 at 1. As argued below, the Company's request is not only overstated, it is unreliable and unsupported and would include in revenue requirement amounts that are in no way "known and measurable". Therefore, the People urge the Commission to reduce this expense by $10.45 million in line with Mr. Brosch's adjustment. AG Ex. 4.1, sched. C-6.

PGL witness Mr. Hoops testified, in his supplemental direct testimony, that the $13.9 million reflects the Company's estimated annual costs for compliance with CDOT regulations that took effect in July 2012 and involve expected increased permit expenses for excavating recently paved streets, new paving and pavement marking requirements, new fees for parking obstructions, and changes to backfill requirements. NS/PGL Ex. 20.0 at 3-5.

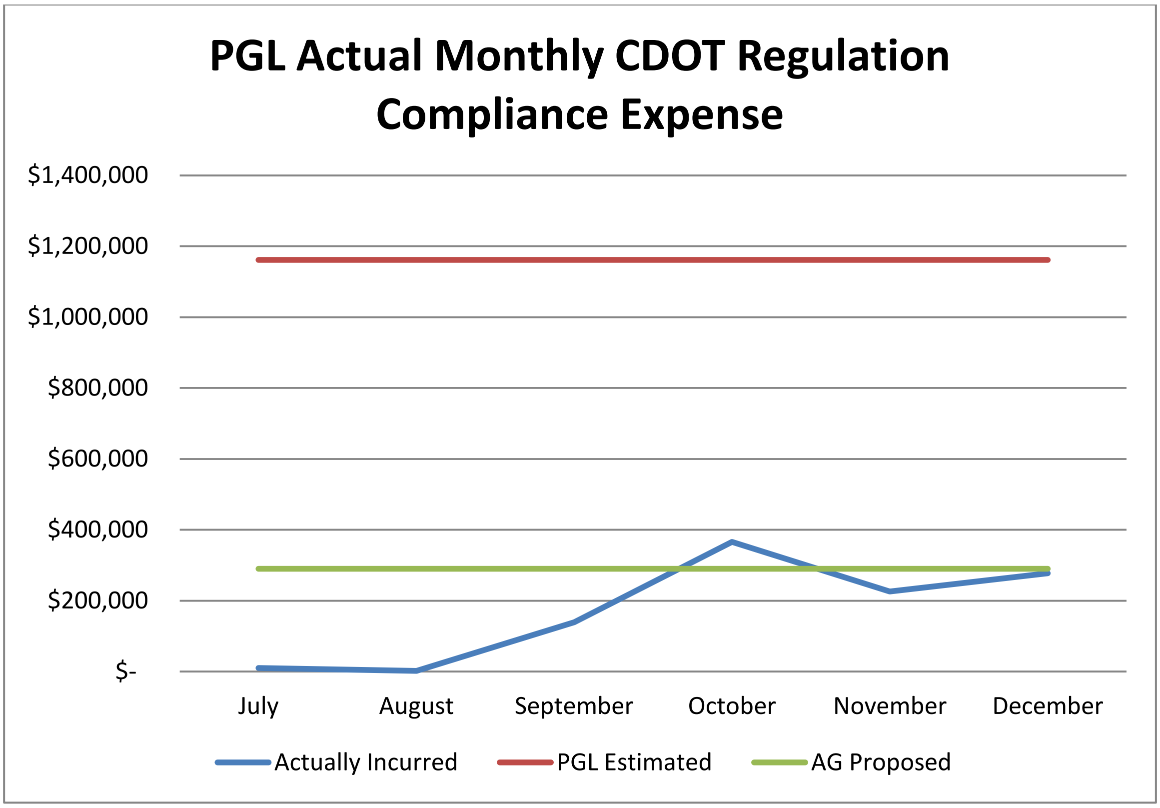
The Company has completely failed to meet its burden of justifying the majority of its requested $13.9 million expense. PGL's testimony on the topic has been limited at best. The

Company, in its supplemental direct case, provided no workpapers or supporting documentation – merely perfunctory descriptions of the total amount sought to be recovered. AG Ex. 1.0 at 46-7. On rebuttal, the testimony of Company witness Mr. Hoops on this subject did not even reach a page in length. NS/PGL Ex. 28.0 at 8. Mr. Hoops merely asserted that the costs were prudent and reasonable, but provided no analysis to support the claim. Instead, the Company papered the record with invoices and bids from what appear to be subcontractors performing repairs or other construction work on main replacement or segments. NS/PGL Ex. 28.1. This "papering" of the docket includes copies of materials provided in response to AG and CUB discovery that actually shows considerable uncertainty in how the new regulations are to be implemented, as discussed in correspondence between PGL and the City, and only $168,510 of actual incurred costs in July, August, September and October of 2012 under the new regulations, while providing nothing to justify the entire $13.9 million addition to O&M expenses being sought by the utility.

At the root of the People's proposed reduction to the Company's unsubstantiated request for money is a need to eliminate the uncertainty and gross speculation in PGL's incremental expense forecast related to new CDOT regulations. As the Company acknowledges in a letter to the Chicago Department of Transportation included in its response to AG Data Request 16.25 (attach 02), "Peoples Gas is struggling with understanding certain changes and also needs time to make procedural changes to implement certain revisions." AG Ex. 4.6 corrected. This correspondence is an admission by Peoples that its proposed adjustment is not "known and measurable" since the changes being imposed by the City are not yet even fully understood by the utility.

The record reflects that the changes to CDOT regulations have been in effect since July of 2012 and the Company has been operating under the new regulations for more than six months. There is no need to charge ratepayers for speculative and overstated cost estimates for compliance when recent actual expenditures are available to quantify the needed adjustment to the revenue requirement. The alternative AG adjustment for CDOT compliance expense accounts for actual costs experienced by PGL in the fourth quarter of 2012 during which the new regulations were fully effective. AG 4.0 at 46-7; AG Ex. 4.1. The People's witness Mr. Brosch reviewed the *actual* costs for compliance and created an adjustment rooted in PGL's own historical experience. The large difference between PGL's proposed recovery from ratepayers and its actual expenses is staggering and is reflected in Table 2 below. The People's adjustment merely attempts to substitute a truly "known and measurable" revisions to test year O&M expenses and charge to the ratepayers only what they owe. No more and no less.

TABLE 2: ACTUAL CDOT COMPLIANCE EXPENSE TRENDS / COMPARISONS



PGL's own actions proposed in correspondence with the City suggest that they are seek to moderate the impacts of CDOT compliance upon the expenses that are incurred. PGL is proposing a grace period during which PGL could negotiate with contractors and, presumably, reduce compliance costs. AG Ex. 4.6 corrected. PGL acknowledged in its response to AG data request 16.25 that it "expects to be in full compliance with all new regulations by January 1, 2013" and that "all methods and timing of CDOT regulation changes have been implemented and approved" except for trench backfill material. AG Ex. 4.6 corrected. These statements belie the Company's protestations that its costs will continue to escalate throughout 2013 or that its overstated estimates of CDOT compliance costs are "known and measurable".

The People's $10.45 million adjustment is reasonable and necessary and is reflective of the only known and measurable costs for compliance with CDOT regulations that is in the record. PGL has not met its burden to justify the much higher forecasted expenditures. Therefore, the Commission should adopt the People's adjustment to CDOT regulations expenses.

6. Productivity Adjustment

AG witness Mr. Brosch proposed a modest ½% per year productivity offset necessary to counter unreasonable and unrealistic inflation assumptions made by the Companies in forecasting their test year O&M expenses. For most non-labor O&M expenses, unless specifically determined otherwise, the Companies' forecasts assumed a default 2.1% and 2.2% annual rate of inflation for 2012 and 2013, respectively. The Companies' assumptions about labor costs, as described in greater detail in the "Vacancy Adjustment" section of this brief, predict higher staffing levels than currently experienced along with higher wage rates, without any offsetting adjustment for assumed improved productivity, and efficiency-driven expense savings. AG Ex. 1.0, 22.23 . The People submit that the Commission should not blindly accept inflation and wage rate assumptions in forecasting test year expenses, but should instead insist upon some assumed improvements in operational efficiency or productivity, particularly when the regulated utility is insisting upon recovery of incentive compensation expenses that are claimed to generate such productivity benefits. The net effect of the AG's proposal reduces the Companies' forecasted test year expenses, by approximately $2.49 million (PGL) and $394,000 (NS) in the test period. AG Ex. 4.1, sched. C-4; AG Ex. 4.2, sched. C-4.

Generally speaking, productivity measures changes in production efficiency – essentially, the Companies' ability to do more work with fewer hours of labor and/or fewer other input resources. Gains in productivity can be achieved by implementing improved operating methods, automating work processes, using technology, training employees, and management oversight. It is very reasonable for ratepayers, who are paying utility management's salaries, to expect utility management to strive for and achieve gains in productivity. AG Ex. 1.0 at 23. The AG adjustment recognizes a modest estimate of these achievable gains by reducing, by ½% per year, PGL and NS asserted test year non-fuel O&M expenses that are not tracked through rate adjustment riders. The cumulative effect of this adjustment over a two year period reflects a modest 1% reduction in forecasted levels of O&M that have been escalated for inflation and wage rate increases, but no offsetting productivity gains in the Companies' test year forecasts.

The AG productivity adjustment addresses only those costs that are within the control of management. The People acknowledge that it is reasonable to not include certain expenses outside of management's control, such as costs for injuries and damages, insurance and postage, and pension and post-employment benefit costs. The AG adjustment also reasonably assumes that productivity gains can be achieved through proper management, an assumption directly supported by the Companies' testimony. Companies' witness Ms. Cleary testified that an incentive metric exists in order to reduce operational costs. NS/PGL Ex. 9.0 at 5. Ms. Cleary further stated that the impetus behind the incentive metric was to reduce the amount of O&M expenses that ratepayers are responsible for. Id. at 4-5. Essentially, the Companies are anticipating productivity gains – as any responsible utility management would.

Despite declaring from one side of their mouth that the Companies anticipate cost reduction efficiency gains, the Companies, from the other side of their mouth, provide a host of excuses as to why any productivity offset is unnecessary or unreasonable. Chief among the Companies' complaints are that workload will be increasing, productivity will be flat or decreasing as new employees are brought on and gaining experience, and the Companies' budgets and forecasts inherently take into account increases in productivity, and further that the People's adjustment is subjective. NS/PGL Ex. 25.0 at 6. The Commission, however, should look past these excuses because they are not only meritless, but the Companies have failed to specifically identify and quantify what assumptions they undertook when making their own productivity gain assumptions. The AG's proposed adjustment, on the other hand, is supported by an examination from AG witness Mr. Brosch.

As to productivity assumptions, Mr. Brosch closely examined the Companies' budgeting assumptions presented in their Schedule G-5 and found that no stated productivity assumptions were made to offset the wage increase rates and applied annual inflation rates without an offset for productivity efforts. AG Ex. 4.0 at 24-25. The main driver behind the Companies' labor forecasts were, in fact, the Companies' unsupported judgments about the level of work expected to be performed in 2013 and their estimates about how many additional employees would be required to perform this work. As for non-labor expenses, the Companies simply used broadly applied general inflation indexing for non-gas expenses. These inflation-only judgments do not provide sufficient reason to impose additional expenses onto the ratepayers without similar and offsetting judgments with regard to achievable productivity improvements.

The Commission should also not assume that the Companies have "inherently" reflected adjustments to productivity in preparing test year expense forecasts. The Companies are asking the Commission to blindly accept as fact that utility management has extrapolated historically and consistently achieved gains in productivity and "inherently" accounted for those gains with no documentation of any specific forecasted cost-savings stated or quantified in the record. The AG's proposed adjustment to assume modest incremental productivity improvement each year would allow the Commission to require some performance by management to achieve incremental productivity improvements that will serve to offset the effects of inflation and wage rate increases that were explicitly factored into test year expense forecasts.

Increased workloads, as well, should not have an impact on the Companies' ability to achieve greater efficiency and productivity. In fact, in response to AG Data Request 16.10, Companies' witness Ms. Gregor explicitly conceded that she "does not believe that productivity improvements cannot occur when workload is increasing." AG Ex. 4.4 at 5. The Companies further agree that "management employees of public utilities like Peoples Gas and North Shore [should] be expected to strive to achieve improved productivity and cost reductions in their day-to-day actions to manage the business." Tr at 74. Therefore, the Commission should not give weight to the Companies' claims that changes in workload somehow excuse management for achieving productivity gains.

As to employee turnover, the People discuss this topic in greater detail in the "Vacancy Adjustment" section of this brief. Simply stated, however, the mere fact that turnover occurs does not lend credence to the Companies arguments against the productivity offset. Turnover is a routine part of business for the utilities and one which the Companies management must be able to overcome and achieve gains over time. The Companies acknowledge this very notion, where in their responses to AG Data Request 16.11, Companies witness Ms. Gregor acknowledge that turnover is not unique to NS or PGL and also "did not conclude that firms that experience turnover of seasoned employees cannot achieve improved productivity." AG Ex. 4.4 at 8. With these acknowledgements in mind, it becomes even more critical to note that none of the Companies' witnesses have testified with certainty where any assumed productivity gains have actually been included in their forecasts. *See, generally,* AG Ex. 4.4.

Finally, the Companies' criticism that the People's adjustment is "subjective" is equally without merit. The Companies acknowledge that a number of forecasted expenses are, themselves, subjective, including, as noted in the Companies' response to AG data request 16.13, "some of the elements of the Companies' rate case test year forecasts of O&M expenses or rate base." AG Ex. 4.4 at 14. When using a forecasted test year, where nearly all of the input amounts are based upon estimates, it is essential that judgment be applied. The People's productivity adjustment is no less subjective than many of the assumptions relied upon by the Companies in preparing their own test year forecasts.

The Companies' excuses and criticisms of the AG proposed adjustment are clearly without merit and should be disregarded by the Commission. Additionally, it is important to note that other state's commissions have implemented productivity offsets to address the reasonable expectation of the ratepayers. The California Public Utilities Commission regularly require offsets for expected productivity improvements. The New York Public Service Commission recently required a 1/2% annual productivity offset in a rate case and noted that such an adjustment was "consistent" with its policy.[33] The Hawaii Public Service Commission similarly applies an annual .76% productivity offset to O&M expenses.[34]

Given the reasonableness of the AG's proposed 1/2% adjustment to O&M, the inability of the Companies to refute that reasonableness, and the actions of sister state's commissions, the Commission should adopt the AG's proposed adjustment.

7. Administrative & General

a. Adjustments to Integrys Business Support costs

As noted throughout this Brief, the Companies have the burden of proving that their proposed test year level of expenses are just and reasonable pursuant to Section 9-201 of the Act. Mr. Brosch proposed downward adjustments to AG Exhibits 1.3 and 1.4 at Schedule C-8, to several categories of Integrys Business Support ("IBS") billings to PGL and NSG where significantly higher forecasted test year charges above historical levels were proposed, because such increased expenses had not been adequately explained in the Companies' filing and responses to AG data requests. He explained that the Companies provided no detailed supporting calculations for their proposed test year O&M expense forecasts for affiliate charges to PGL and NSG as part of the filed Direct Testimony, Exhibits and Workpapers, so considerable effort was required by the AG to discover and evaluate the basis for such forecasts. AG Ex. 1.0 at 48-49. In the AG rebuttal case, several of these initial adjustments were either revised or retained based on the receipt of additional information from the Companies.

Inquiries made by the AG related to Integrys Business Support, LLC forecasted expenses chargeable to PGL and NSG in the test year revealed very large projected IBS cost increases that were not consistent with recent actual spending levels at IBS, and could not be explained by either general wage increase ("GWI") adjustments or by escalation rates applied for inflation. For these unusual projected expense levels that are not consistent with historical actual spending, Mr. Brosch proposed elimination of the unexplained variances in such costs unless and until the Companies provide in their rebuttal evidence a complete and detailed justification for such projected large expense increases. Quite simply, the Companies failed to meet their burden of explaining and justifying the basis for such large, projected cost increases. AG Ex. 1.0 at 48-49.

Mr. Brosch's Schedule C-8 at Exhibit 1.3 and 1.4 include captioned "Unexplained Variance" amount categories. This, in fact, was the caption that the Companies used in responding to the referenced AG data requests. These variance amounts are above and beyond the increases caused by proposed escalations within the Companies' forecasts for general wage increases and for general inflation. Only brief and generalized descriptions of anticipated future costs or known causes for expense increases were initially provided by the Companies for these amounts. Mr. Brosch testified that more detailed supportive information was required before these forecasted large expense increases from IBS should be allowed into test year expense amounts to be paid by ratepayers. AG Ex. 1.0 at 49.

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[33] Order Establishing Rate Plan, June 18, 2010, Central Hudson Gas & Electric Corporation Case 09-E-0588, 0589, page 6. Available at: http://www.cenhud.com/pdf/2010_rateplan.pdf

[34] Approved rates for the Hawaiian Electric Companies are subject to annual adjustment pursuant to a Rate Adjustment Mechanism ("RAM") between triennial traditional rate cases. In calculating RAM rate adjustments, utility O&M labor costs are escalated for contractual union wage increase percentages that are then reduced by an annual 0.76 percent productivity offset and non-labor expenses are escalated using an inflation factor that is net of economy-wide productivity effects. A copy of the Rate Adjustment Mechanism tariff of Hawaiian Electric is available at: http://www.heco.com/vcmcontent/StaticFiles/FileScan/PDF/EnergyServices/Tarrifs/HECO/HECORatesRAM.pdf

He noted that the projected test year expenses listed in Schedule C-8 are much larger than historically incurred cost levels. AG Ex. 1.11, attached to Mr. Brosch's Direct testimony, includes copies of the Companies responses to data requests AG 3.06, Attachment 7 and AG 3.14, Attachment 1 which contain this information, as well as the Companies' very limited explanation of, "Key Drivers of 2011-2013 Test Year Increase/(Decrease)" amounts. The IBS line item forecasted expenses Mr. Brosch challenged are those line items in these Attachments with projected test year 2013 expenses (1) that greatly exceed the recorded "Actual" expenses in 2010, 2011 and in 2012, to date; (2) where the "Key Drivers" do not fully justify the "Unexplained Variance" in the response; and (3) where the total projected IBS departmental costs exceed historical cost levels by significant amounts. AG Ex. 1.0 at 50.

The single largest element of Mr. Brosch's adjustment challenging the Company's IBS forecasted expenses relates to IBS Depreciation on line 9. Yet, the only explanation of "Key Drivers" for this increase was the Company's Work Asset Management System, transaction based software and other net assets. Given the fact that proposed depreciation amounts far exceed the recorded expense levels in 2010, 2011 and 2012, to date, Mr. Brosch testified that considerably more detailed calculations and explanations should be produced to refine these estimates before they become part of the PGL and NSG revenue requirements. *Id.*.

It is important to note that IBS does not provide services to PGL, NSG and its other affiliates solely at "cost". In addition to assigning or allocating its incurred costs, IBS also charges a return on investment ("ROI") to its affiliates. For the test year, the ROI billings to PGL and NSG are estimated to be $1.8 million and $0.7 million, respectively.[35] The forecasted year return on IBS investment is calculated by applying a pre-tax weighted cost of capital rate to estimates of IBS net book value of assets. Mr. Brosch incorporated an additional adjustment, set forth at AG Exhibits 1.3 and 1.4, Schedule C-9, to synchronize the ROI with the proposed pretax weighted cost of capital being recommended by the AG, so as to recognize the effects of the refinancing of higher cost debt described later in this testimony, and to reflect the lower return on equity most recently approved by the Commission in Docket Nos. 11-0280/11-0281, Cons., an adjustment the Companies acknowledged was necessary. AG Ex. 1.0 at 51.

In their rebuttal case, NS-PGL witness Gregor states she disagrees with Mr. Brosch's proposed adjustments to IBS costs, except for two minor adjustments. Ms. Gregor also indicated that Peoples Gas' responses to AG data requests 12.12 through 12.20 and North Shore's responses to AG data requests 12.1 through 12.9, received by the AG after the filing of Staff and Intervenor Direct Testimony, provided additional information explaining the forecasted expense increases in each of the IBS home centers, and that these explanations show that these costs are reasonable other than the two minor adjustments.[36]

The "two minor adjustments" that the Companies made in response to Mr. Brosch's adjustments, as explained in more detail by Ms. Gregor, involve the removal of the PGL and NSG shares of costs for $250,000 of consulting fees in IBS home center AB2 and $165,000 of software maintenance expenses that were "double booked" in estimating IBS test year expense levels. NS-PGL Ex. 25.0 at 5. With regard to the other IBS charges to PGL and NSG that were challenged, no specific rebuttal testimony is offered for the unexplained variances in the IBS home centers, listed in AG Exhibit 1.3 and 1.4 at Schedule C-8. Instead, Ms. Gregor attaches copies of responses made by the Companies to certain AG data requests within her NS-PGL Ex. 25.3P and NS-PGL Ex. 25.3N from which she claims that,

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35 AG Ex. 1.0 at 50, *citing* PGL Response to data request PGL BAP 16.04, Attachment 1.

36 NS-PGL Ex. 25.0, page 5, lines 92-102.

"…additional information explaining the increases in each of the home centers was provided. These explanations show that these costs are reasonable other than the two minor adjustments." NS-PGL Ex. 25 at 6.

While in some instances the additional information was sufficient to fully explain the proposed cost increases from IBS, in other instances the additional information either supported a revised adjustment amount or retention of the AG's original adjustment. The adjustment originally listed at line 1 of Schedule C-8 for IBS charges for information technology cost center A59 charges to PGL and NSG was eliminated because of the software maintenance duplicate charges that have been corrected in the Companies' rebuttal revenue requirement calculation, as one of the two conceded adjustments discussed by Ms. Gregor, and because the explanations for the balance of higher charges from IBS home center A59 that were provided in response to data requests AG 12.12 and AG 13.18 are sufficient to justify the proposed higher costs.[37]

AG Exhibit 4.1 and 4.2, Schedule C-8, attached to Mr. Brosch's rebuttal testimony, also now reflects elimination of your adjustment on line 2 to exclude the "unexplained variance" amount associated with test year estimated charges from IBS for the "Safety Health and Wellness" home center A45. Mr. Brosch testified that the considerable additional detailed information provided in the Companies' response to data requests AG 12.14 and AG 13.12 explaining the Integrys wellness program initiatives and expected benefits to the Companies from these efforts were sufficient to justify the expense.[38] Mr. Brosch concluded that reduced workers' compensation costs and other indirect benefits from reduced employee health benefit expenses in future years should provide a payback on these incremental costs planned to be incurred in the test year.

Mr. Brosch also revised the adjustment at Schedule C-8, line 3, applicable to IBS home center A06 for Corporate Controller allocated costs. He explained that an itemized breakdown by vendor of IBS Corporate Controller charges was provided by the Companies. Corporate Controller IBS actual payments to vendors in 2011 totaled $3.3 million and in the 10 months ending October 31, 2012 totaled $2.6 million. In the forecasted test year, however, about $5.0 million of payments to vendors by IBS is forecasted. This comparison illustrates the apparent overstatement of total estimated vendor charges for services to the IBS Corporate Controller organization, prior to allocations among Integrys affiliates. Additionally, the itemization of IBS Corporate Controller forecasted 2013 expenses includes more than $1 million for International Financial Reporting Standards ("IFRS") consulting work in 2013 that is highly speculative, and $140,000 for potential acquisition and merger-related services that are also speculative and, as such, should not be charged to the regulated utilities in Illinois if actually incurred by IBS. Mr. Brosch included a copy of the PGL responses to data request AG 13.11 and AG 12.02 with excerpts of Attachments 1 within AG Exhibit 4.7 to support these conclusions. Footnote (c) on Schedule C-8 explains a revised adjustment for IBS Corporate Controller forecasted expenses that would reduce such charges to an allocated PGL/NSG share of actual vendor charges for the year-to-date October 2012 period, times 12/10 months to annualize the amounts. AG Ex. 4.0 at 53.

Upon review of additional supporting information supplied by the Companies in response to various AG data requests, Mr. Brosch eliminated the adjustments previously proposed at lines 4 through 7 of AG Exhibits 4.1 and 4.2, having concluded that the estimated IBS charges for which variances that were previously unexplained are now sufficiently documented and appear reasonable, as indicated in footnotes (b) and (d). For IBS Utility

[37] AG Ex. 4.0 at 52; PGL's Response to data request AG 12.12 is contained in the first four pages of NS-PGL Ex. 25.3P. PGL's response to AG 13.18 explains and quantifies the downward adjustment to software maintenance charges conceded by the Companies in rebuttal.

[38] AG Ex. 4.0 at 53; A copy of PGL's response to AG 12.14 is included in NS-PGL Ex. 15.3P.

Group Executive Office allocated charges at line 5 of Schedule C-8, the adjustment now included by the Companies in rebuttal to reduce forecasted consulting fees[39] is an additional reason why the AG-proposed adjustment for this element of IBS allocated costs is no longer necessary. AG Ex. 4.0 at 54.

Mr. Brosch's initially proposed adjustment to reduce IBS legal charges to the Companies, at line 8 of Schedule C-8, has *not* been revised. The information provided by the Companies in response to data requests AG 12.19 and AG 13.16 supports a conclusion that legal fees in total have been overstated in the 2013 forecast prepared for the IBS Legal cost center. This overstatement can be observed in comparisons of forecasted 2013 amounts to recorded 2010, 2011 and year-to-date 2012 spending in the Companies' response to AG 12.08 and 12.19 within Ms. Gregor's NS-PGL Ex. 25.3P at Bates PGL 0018659 through PGL 0018661. AG Ex. 4.0 at 54-55. The People requested a more detailed breakdown of recorded historical legal fees, forecasting assumptions and calculations supportive of test year IBS Legal forecasted expenses in data request AG 13.16 to assist in the analysis of forecasted spending levels, but the Companies objected to providing additional breakdowns and did not provide any additional support for the proposed forecasted 2013 expense levels. A copy of the response to data request AG 13.16 is included within AG Exhibit 4.8.

Mr. Brosch provided a revised adjustment for IBS depreciation expense at line 9 of AG Schedule C-8. He explained that IBS allocated charges to PGL and NSG include depreciation and amortization expense for assets employed by IBS to provide services to its affiliated companies. Mr. Brosch's analysis of IBS depreciation amounts forecasted for the 2013 test year indicated unreasonably large increases in projected amounts allocable to PGL and NSG. An adjustment was proposed in his Direct Testimony based upon the overall unexplained variance for such increased charges within the response to data request AG 3.14. Additional information provided by the Companies in response to AG data requests indicates the need for a more specific adjustment than for IBS depreciation, which is set forth in footnote (f) of Schedule C-8. This more specific adjustment is to update depreciation charges for the updated in-service date expected to be achieved in June of 2013 for the GAP software development project to improve the Work Asset Management ("WAM") System, as more fully explained in the Companies' response to data request AG 12.20.[40] Additional follow-up discussion of the WAM GAP project was provided in the response to AG 13.10, which is included within AG Exhibit 4.9.

According to the response to AG 13.10(d)(xi), "The WAM GAP project will be in service in June, 2013. Updated depreciation numbers will be reflected in surrebuttal." The revised AG adjustment at line 9 of Schedule C-8 is needed to replace the full year of WAM GAP depreciation with a half-year of such depreciation based upon an assumed mid-year in service date for the project. AG Ex. 4.0 at 55-56.

Finally, Mr. Brosch originally included in his Direct exhibits an adjustment to update the IBS return on investment at AG Exhibits 1.3 and 1.4, Schedule C-9. The Companies' Rebuttal Testimony indicates that PGL and NSG do not contest making an adjustment to update the IBS return on investment charges that appear within the Utilities' operating expenses.[41] However, the Companies' adjustment for this purpose is tied to the level of return on investment most recently awarded by the Commission in Dockets 11-0280 and 11-0281, rather than the updated rates of return being proposed by the AG in Schedule D. In AG Exhibits 4.1 and 4.2, Mr. Brosch continued to update the IBS return on investment expense amounts as proposed in his Direct Testimony, but added a line 11 amount to account for the

[39] See NS-PGL Ex. 25, page 5, line 104 and NS-PGL Ex. 25.4.

[40] This response is included in NS-PGL Ex. 25.3, at Bates PGL 0018429 through PGL 0018582.

[41] NS-PGL Ex. 26.0, page 5, line 107.

incremental adjustment now being made by the Companies, that revises the IBS return levels to the Companies' previously authorized overall return levels.

These adjustments, as provided in their final format and based on the evidence in the record, as listed in AG Ex. 4.1 and 4.2, Schedules C-8 and C-9, should be adopted by the Commission.

b. Advertising Expenses

c. Charitable Contributions

d. Institutional Events

8. Depreciation

a. Bonus Depreciation

b. Derivative Adjustments from Contested Adjustments

9. Rate Case Expenses

D. Taxes Other Than Income Taxes and Invested Capital Taxes (Payroll) (Uncontested Except for Invested Capital Tax and Derivative Adjustments from Contested Adjustments)

1. Invested Capital Tax Computation and Derivative Adjustments

Invested capital tax expenses are formula-driven, applying a 0.8 percent tax rate to the simple average of the taxpayer's equity and long term debt capital as of the beginning and end of each calendar year. To calculate an estimate of this tax, PGL and NSG have forecasted their invested capital balances at the beginning and end of 2013, which has the effect of calculating a tax amount that will be recorded as expense and actually paid in 2014. AG witness Brosch testified that such a mismatching of test year expenses, including expected 2014 amounts within a 2013 test year is improper and serves to overstate the revenue requirement. AG Ex. 1.0 at 42.

To make matters worse, Company witness Ms. Moy then calculates an additional invested capital tax amount at Schedule C-2.14 which she describes as "…necessary in order to recognize the additional Illinois invested capital tax which Peoples Gas will incur due to the proposed increase in operating income. An increase to operating income correspondingly results in an increase to Peoples Gas' retained earnings and thus to its total capitalization, which is the variant factor in the invested capital tax calculation." This further adjustment is wrong for several reasons and should be rejected.

Schedule C-11 in AG Exhibits 1.3 and 1.4 (and replicated in rebuttal exhibits AG 4.1 and 4.2) sets forth Mr. Brosch's proposed calculation of test year Invested Capital tax. For the beginning of the year, the Schedule C-11 calculation employs amounts taken directly from the most recently Invested Capital tax returns filed by the Companies, as provided in response to data requests AG 8.10 and 8.20 for NSG and PGL, respectively. These January 1, 2012 amounts entered into column (B) of Schedule C-11 are then combined with estimated invested capital balances expected to exist at December 31, 2012, as provided in the Companies' response to Staff data requests BAP 5.01 and BAP 5.02. Averaging the beginning and end of year 2012 balances in column D, a 1.0 Illinois apportionment factor and 0.8 percent tax rate are then applied to calculate an estimate of the tax amount that will be accrued on the Companies' books in calendar 2013. AG Ex. 1.0 at 43.

As explained by Mr. Brosch, the Companies' proposed amounts are overstated because the taxes calculated by PGL and NSG are based on estimated investment levels in 2013, and would not be payable or expensed on the books until *after* 2013. In response to data requests AG 8.10 and 8.20 the Companies admitted that "The Illinois Invested Capital tax is recorded on the books as a monthly accrual. The monthly accrual is based upon last year's tax divided by twelve (months)." For this reason, the estimated tax calculation for the 2013 test year should mirror the inputs that will appear on the tax return to be filed by March of 2013, based upon beginning and end-of-year 2012 invested capital balances. *Id.* at 44.

Another reason the Company's proposed test year expenses are overstated is Ms. Moy's proposed Schedule C-2.14 adjustment to include additional tax dollars for an alleged prospective impact from a rate increase in the instant dockets. Her premise that, "An increase to operating income correspondingly results in an increase to Peoples Gas' retained earnings and thus to its total capitalization" is factually correct, but does not accurately predict future Invested Capital taxes in the test year for several reasons:

- It fails to consider any dividends that may be paid out of future retained earnings, which would directly reduce retained earnings and total capitalization.
- It fails to incorporate all other influences upon actual future earnings, such as variations in revenues, expenses, changing interest rates or regulatory disallowances.
- It assumes approval of the Company's proposed level of return on equity and rate base, which amounts are disputed in these dockets.

AG Ex. 1.0 at 44-45. No adjustment to Invested Capital tax should be made in connection with the rate changes approved in these dockets, for all the reasons just stated, and because rate changes alone cannot be shown to accurately define test year invested capital tax expense levels. A complete and reasonable calculation of test year invested capital taxes is set forth at Schedule C-11 that needs no further adjustment for rate changes or other isolated issues that may impact future earnings and invested capital levels.

PGL, in fact, admitted that its Invested Capital Tax amount proposed for the test year is overstated and should be adjusted downward. In response to data request AG 10.28, the Company stated, "The 2013 (test year) Invested Capital Tax proposed amount is $12,086,600 (which was adjusted downward to $10,359,000 in our response to BAP 5.01(e))." However, the Company's proposed revised amount of $10,359,000 is still overstated, relative to the calculations in Schedule C-11 because of the use of input information that yields tax estimates that would not be recorded within 2013 for the reasons described earlier. This overstatement is amplified by Ms. Moy's inappropriate rate increase factor-up adjustment that would further increase PGL's proposed tax amount by $356,000. *Id.* at 45.

In their rebuttal case, NS-PGL witness Sharon Moy is very brief on this topic and does not respond to Mr. Brosch's explanation as to why the Companies' calculation method for this tax results in an overstatement of the tax expense that is to be recorded in the 2013 test year.[42] Instead, Ms. Moy focuses solely upon the Companies' derivative adjustment that improperly assumes that test year Invested Capital Tax should be increased as a direct result of the rate change ordered in these dockets. Mr. Brosch's Direct testimony fully explained why no such derivative adjustment is appropriate and will not be repeated here.

The more substantive rebuttal on this issue is sponsored by Mr. Stabile. He claims that, "The Utilities have updated invested capital tax estimates to be consistent with the long term debt and equity in the rebuttal filing in this preceding." NS-PGL Ex. 30.0 at 34. But Mr. Brosch noted that this is the precise reason why the Companies' proposed level of Invested Capital tax is overstated. As explained in hid Direct testimony, the test year 2013 recorded invested capital tax expense amount will be based upon calendar 2012 recorded capital balances, not the later test year amounts. The Companies' proposed method of calculation for this tax results in estimation of a tax amount that will actually be recorded in accounting periods after the test year, amounts that are inconsistent with the rest of the asserted 2013 test year revenue requirement. AG Ex. 4.0 at 42.

[42] NS-PGL Ex. 26.0 at 10.

Mr. Stabile's rebuttal first provides a legal definition of invested capital tax, stating, "“Taxable period” is defined as each period which ends after the effective date of the Gas Revenue Tax Act and which is covered by an annual report filed by the taxpayer with the Commission. 35 ILCS 615/1."[43] He then opines that, "Since the 2013 test year will ultimately be an annual period that is the subject year of an annual report to the Commission, the annual period for the invested capital tax is 2013." Finally, Mr. Stabile argues that Mr. Brosch and Mr. Smith, "…are using 2012 information to calculate their adjustment" and concludes that, "They both indicate that the tax for 2013 is based upon 2012 data, but neither provides any basis for that conclusion."[44]

Focusing first on the Companies' proposed calculation of this tax, a tax return that includes financial data for an "annual period for the invested capital tax" of 2013 as proposed by Mr. Stabile will not be filed until 2014. As Mr. Brosch noted in his Direct Testimony, the taxes calculated by PGL and NSG that are based on estimated investment levels in 2013 would not be payable or expensed on the books until *after* 2013. Thus, Mr. Stabile's calculation approach actually yields an estimated tax expense for the following tax year, calendar 2014. It is not reasonable to include within a 2013 test year estimated invested capital expenses that are not payable until 2014 and will not be recorded on the Companies' books until 2014. AG Ex. 4.0 at 43.

Mr. Stabile next asserts that Mr. Brosch provided "no basis" for a conclusion that the tax for 2013 is based upon 2012 data. NS-PGL Ex. 30.0 at 35. This criticism is mistaken. Mr. Brosch clearly stated in his Direct testimony that, in response to data requests AG 8.10 and 8.20, the Companies admitted that "The Illinois Invested Capital tax is recorded on the books as a monthly accrual. The monthly accrual is based upon last year's tax divided by twelve (months)."[45] Because of this fact, the estimated tax recorded for the 2013 test year will be based upon the financial data that will appear on the tax return to be filed by March of 2013, which is in turn based upon beginning and end-of-year 2012 invested capital balances. AG Exhibit 4.5 contains copies of the Companies' responses to Data Requests AG 8.10, 8.20, 10.13 and 10.28 which all support the "basis" for the AG's positions. These responses document how the Companies account for Invested Capital Tax while revealing two obvious facts:

1. No complex calculations involving estimated capital balances at the beginning and end of 2013 are needed to accurately determine the Invested Capital tax that will be recorded on the Companies books in 2013, and
2. The Companies' further adjustment to "factor-up" the already overstated estimate of 2013 tax amounts for "additional revenues" from the rate increase, as described by Ms. Moy, simply adds to the overstatement of calendar 2013 Invested Capital taxes.

AG Ex. 4.0 at 44; AG Ex. 4.5. The method of calculating the 2013 Invested Capital tax that is set forth in AG Exhibit 4.1 and 4.2 at Schedule C-11 properly employs 2012 financial data to calculate the estimated tax amount that will be expensed by the Companies on their 2013 accounting records.

According to Mr. Stabile's rebuttal, "The Utilities have updated invested capital tax estimates to be consistent with the long term debt and equity in the rebuttal filing in this preceding."[46] Since AG Exhibits 4.1 and 4.2 use the Companies' Rebuttal revenue requirement as a starting point, the "Company-proposed Test Year Level of Invested Capital Tax" at line 10 of Schedule C-11 has now been revised to reflect the Companies' updated

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43 NS-PGL Ex. 30.0 at 34.
44 *Id.* at 35.
45 *See* AG Ex. 1.0 at 44.
46 NS-PGL Ex. 30.0 at 34.

position regarding such tax amounts in rebuttal. No substantive changes have been made to the calculations employed to determine the “Annual Invested Capital Tax to Be Recorded and Paid in 2013” at line 9 of Schedule C-11.

For all of the reasons presented above, the AG-proposed adjustment to this expense item should be adopted.

E. Income Taxes (Including Interest Synchronization) (Derivative Adjustments from Contested Adjustments)

1. Appropriate Methodology to Reflect Change in State Income Tax Rate (see also Section V.C.6.a.)

By way of reference, the People incorporate its arguments presented in Section IV, 6(a) in this section.

F. Gross Revenue Conversion Factor

1. Methodology

In her rebuttal testimony, NS-PGL witness Moy takes issue with the Gross Revenue Conversion Factor set forth at Schedule A-1, where part of the required revenue increase is satisfied by a ratable increase in Late Payment Charge revenues as described in footnote (c) on AG Schedule A-1. According to Ms. Moy, “The Utilities have already accounted for the fact that every dollar of incremental base rate revenue will create incremental late payment charge revenues in the revenue requirement. Thus, Mr. Brosch’s adjustment would result in double counting.”[47]

In fact, there is no “double counting” of incremental Late Payment Charge revenues under the AG’s approach. While it is true that PGL and NSG have accounted for incremental Late Payment Charge revenues arising from the rate increase at NS-PGL Ex. 26.1P/N in column (F) at line 10, it is important to note that the starting point for the AG’s revenue requirement calculations is column (E) of this Exhibit, which is *prior to* such incremental Late Payment Charge revenues. This fact can be verified by looking at AG Exhibit 4.1 in Schedule C, where PGL’s “Other Revenues” in column (B) are $15,386 (thousand) which does not include the incremental $885 (thousand) of incremental Late Payment Charge revenues arising from PGL’s proposed revenue increase. An accounting for these “Other Revenues” is therefore needed in AG Schedule A-1, the Gross Revenue Conversion Factor, to accomplish the same accounting for incremental Late Payment Charge revenues from the revenue increase that the Companies apparently agree should be recognized. The AG Proposed revenue conversion factor on Schedule A-1 includes a factor at line 2 to “Add: Other Operating Revenues” that has the effect of including Late Payment Charge revenue growth associated with the AG-proposed revenue requirement, which amounts then appear in Schedule C, page 1, column (E), line 3 for each of the Companies. AG Ex. 4.0 at 4-5.

Accordingly, Ms. Moy’s criticisms of Mr. Brosch’s calculation of the Late Payment Charge revenues within the Gross Revenue Conversion factor should be rejected.

[47] NS-PGL Ex. 26.0 at 12.

2. Late Payment Charge Ratio

By way of reference, the People incorporate the argument presented in Section V, F (1) in this section.

G. Net Operating Loss (Derivative Adjustment based on NOL Tax Asset)

VI. RATE OF RETURN

A. Overview

B. Capital Structure

C. Cost of Short-Term Debt

D. Cost of Long-Term Debt

There are two disputed issues with regard to the cost of long term debt. The first issue is factual and involves how to best determine the cost rates to be used for new issuances of debt that are planned to occur within the test year using an average cost calculation methodology. The second issue is conceptual and relates to the Companies' proposed use of a year-end rate base to increase revenue requirements at the same time the Companies' are resisting use of the lower annualized cost rate for long term debt *as of year-end* that would reduce revenue requirements by fully reflecting debt cost savings arising from refinancing of older, higher-cost debt. This second issue is conditioned upon Commission acceptance of a year-end rate base, as proposed by the Companies (see separate discussion of this issue in the Year-End Rate Base Section, infra), which acceptance should dictate consistent utilization of a year-end long term debt cost rate that annualizes the savings realizable by the Companies from the debt refinancing transactions scheduled to occur within the test year.

With respect to the first, factual issue, the Companies' respective Revised Schedule D-1 reveal that NS proposes a 4.64% cost of long term debt, and PGL proposes a 4.47% cost. NS/PGL Ex. 38.0 at 2; NS/PGL Exs. 38.1N and 38.1P. These amounts are quantified using an average cost rate for all debt outstanding during the test year, including periods before and after the refinancing of certain older, higher-cost debt. AG witness Brosch recommends a slight adjustment to both of these figures, also using an average cost rate approach: to 4.60% for NS and 4.46% for PGL. AG Ex. 4.1, Sched. D; AG Ex. 4.2, Sched. D. Although the recommended adjustments are slight, they are nonetheless important because they seek to more appropriately reflect the Companies' *actual* long term debt costs.

The Companies' calculation of Long Term Debt cost overstates the expected interest coupon rates for each of the forecasted new issuances. The Company's estimated cost rates were based upon projected yields for 10-year treasuries in the relevant future periods, plus an estimated risk premium for each utility. See AG Exhibit 1.12 at 1, 2, 4, 5. The Companies have made it clear that they do not wish to rely on recent, actual debt cost information, despite it being the best available information upon which to calculate the costs of long term debt. AG Ex. 4.0 at 68. Rather, the Companies claim that speculative forecasts are the best available information. NS/PGL Ex. 23.0 at 7. The trouble with this approach is that, in the current low-interest rate environment, it is typical for forecasts to forecast interest rates to be initially higher. As the date of the debt issuance nears, it is also typical for those forecasts to be revised downward. An example of this trend is NS's planned May 2013 debt issuance, which originally was projected at a cost rate of 4.75%, but only months later, this forecast was reduced to 4.20%. Similarly, the NS September 2013 issuance was estimated to cost 4.95% but has since been reduced to 4.45%[48]. There are additional, real-world examples

[48] Until PGL filed its surrebuttal testimony, PGL listed a "New Issue" of $100 million of long term debt on 11/01/12 recognizing an estimated cost rate of 4.03%; however, this debt issuance actually occurred at a final

taken from the Companies own data that illustrate this trend.[49] The trend reliably demonstrates that, in the current environment, long term debt costs should not be based on forecasted costs far removed from the issuance date. Ratepayers should not be locked into a long-term commitment to pay for overstated debt costs on new issuances, when it is expected that these costs will actually be lower given recent, actual issuances made by these Companies.

The second issue merits Commission attention only if the Companies are allowed to employ a year-end rate base. As explained by AG witness Brosch, the Companies utilize an average accounting method for outstanding monthly debt balances and cost rates. AG Ex. 1.0 at 57-8; see NS/PGL Sched. D-3. If the Companies prevail in their proposed utilization of a year-end rate base, the People recommend utilizing a year-end costing approach to quantify the cost of long-term debt. This is essentially a matter of fairness and consistency. The Companies should not be allowed to quantify rate base at year-end to increase revenue requirements, while ignoring the declining costs of long term debt that would be lower if consistently annualized at year-end. The Companies use of this average monthly accounting method for outstanding bonds is grossly inconsistent with the Companies' advocacy for use of a year-end rate base.[50] Further compounding the Companies already overstated revenue requirements, the Companies have made it clear that they expect to refinance older higher cost bonds at currently lower market interest rates during the 2013 test year. AG Ex. 4.0 at 68. Nonetheless, they have elected to use an average Long Term Debt cost rate calculation approach that is inconsistent with their year-end rate base. The result is that ratepayers are denied full participation in the annual interest savings resulting from such refinancing.

E. Cost of Common Equity

F. Weighted Average Cost of Capital

VII. WEATHER NORMALIZATION (Uncontested)

VIII. COST OF SERVICE

A. Overview

B. Embedded Cost of Service Study – Uncontested

IX. RATE DESIGN – (Residential Rate 1 Rate Design/Discussion of Fixed Cost Recovery)

Beginning with the filing of its 2007 rate case in ICC Docket No. 07-0241/0242, the Companies have sought significant increases in the flat, monthly customer charges of residential customers, claiming that all of its costs are "fixed," or as the Companies assert, "costs do not vary with the volume of gas delivered to customers." NS Ex. 12.0 at 9 (Grace); PGL Ex. 12.0 at 9. Much to the chagrin of the People, and despite unequivocal evidence from the Companies' own cost studies to the contrary detailing substantial costs tied to customer demand for natural gas, the Commission for the most part has not challenged that assumption. The result has been an unprecedented increase in the last five years in the flat, monthly customer charge of residential customers' bills, with the lowest users of natural gas

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coupon rate of 3.98%. PGL appears to have accepted the lower final coupon rate as Mr. Brosch recommended in his testimony. AG Ex. 4.0 at 66.

[49] For PGL, a second "New Issue" of $200 million of long term debt on 9/01/13 at an estimated cost rate of 4.03% is recognized, at an estimated coupon rate of 4.45%. This cost rate is higher than current capital market cost rates. For NS, a "New Issue" of $55 million of long term debt on 5/01/13 at an estimated cost rate of 4.20% is recognized. This cost rate is higher than current capital market cost rates.

[50] For other previously stated reasons, the People find the Companies' use of a year-end rate base objectionable, and acknowledge only that the Companies advocate for the use of the year-end rate base.

subsidizing the highest users of the Peoples Gas and North Shore Gas delivery systems by extraordinary margins.

The Companies' rate design proposals in this docket continue this "all costs are fixed" charade, with proposals to recover 80% of costs through the customer charge, the continuation of Rider VBA, an unlawful rider that decouples revenues from sales, and a conditional Straight Fixed Variable ("SFV") tariff, that would trigger substantially increased flat rate charges (and an end to variable delivery service charges) that would take effect automatically should (1) the Illinois Appellate Court in an existing appeal of Rider VBA reverse the Commission's adoption of the rider in the Companies' 2012 rate case, Docket No. 11-0280/0281, or (2) the Commission otherwise terminate the rider. Under that tariff, residential Heating customer monthly customer charges would jump from the current $22.25 to $46.97 for PGL customers and from $22.00 to $36.95 for NS customers. As discussed below, the Commission should reject the Companies' proposed rates, because they are inequitable, contradict cost-causation principles and continue unsupportable cross-subsidies by the Companies' lowest usage heating customers to the highest usage customers. The conditional SFV tariff should likewise be rejected because it is patently unlawful, as discussed further *infra*. The People urge the Commission to revisit and reject the Companies' rate design proposals based on the unequivocal evidence presented in the Companies' ECOSS, which clearly demonstrate that usage matters when it comes to cost incurrence, and that continuing to recover more costs through the flat, customer charge for heating customers perpetuates inequitable subsidies of high usage customers by low usage customers.

Cost-Causation Principles and the Companies' Own ECOSS Support Rejection of the NS-PGL Rate Design Proposals.

In the last five years, PGL and NS customers have endured astounding increases in the flat, customer charge portion of their bills, as the Companies seek to remove all risk from cost recovery and guarantee the recovery of residential customer revenues, regardless of the weather. As noted in AG Cross Exhibit 24, the customer charge for North Shore Gas residential customers has increased from $8.50 in 2007 to the current $22.00, an increase of 159% over the last five years. North Shore proposes to continue the march toward 100% recovery of costs through the customer charge for heating customers in this docket, with its proposal to increase the customer charge to $29.56, with the result of 80% of its costs being recovered through that flat charge. If approved by the Commission, the Company's customer charge will have increased an astronomical 248% since 2007, as shown below:

History of North Shore Residential (S.C. **1**) **Rates: 2007 to Present Year**	**Customer Charge**	**First 50 therms**	**Over 50 therms**
2007	$ 8.50	23.151 ¢	12.200¢
2009	$13.50	23.803¢	6.356¢
2011	$17.80	26.036¢	7.319¢
2012	$22.00	16.942¢	5.032¢
% Change 2007-2012	159%	-27%	-59%

NS rebuttal	*$29.56 (*Htg)	6.866¢	6.866¢
% Change 2007 to 2013, proposed by NS	248%	-70%	-44%

AG Cross Ex. 24.

As noted in AG Cross Exhibit 25, the customer charge for Peoples Gas residential customers has increased from $9.00 in 2007 to the current $22.25, an increase of 147% over the last five years. Peoples Gas proposes to continue the march toward 100% recovery of costs through the customer charge for heating customers in this docket, with their proposal to increase the customer charge to $37.58. If approved by the Commission, the Company's customer charge will have increased an astronomical 318% since 2007, as shown below:

History of Peoples Gas Light Residential (S.C. **1) Rates: 2007 to Present Year**	**Customer Charge**	**First 50 therms**	**Over 50 therms**
2007	$ 9.00	36.375¢	11.445¢
2009	$15;50	33.606¢	10.580¢
2011	$19.50	33.372¢	12.360¢
2012	$22.25	25.963¢	11.806¢
% Change 2007-2012	147%	-29%	3%
PGL rebuttal	*$37.58* (Htg.)	10.566¢	10.566¢
% Change 2007 to 2013, proposed by PGL	318%	-71%	-8%

AG Cross Ex. 25.

In its 2012 Rate Order in ICC Docket No. 11-0280/81, the Commission expressed concern about the inequitable bill impacts experienced by low users of natural gas associated with the Commission's embrace of recovering more costs through the flat, customer charge, as compared with the variable per therm charges that appear on customer bills. The Commission noted, "The trend in the Companies' last three rate cases has been to request substantial increases in the customer charge, which may impact low use customers in excess of their cost of service or their contribution to demand-related costs." 2012 Rate Order at 188. The Commission specifically directed the Companies to present an embedded cost of service study ("ECOSS") to distinguish between low use and high use customers. The Commission stated, "Such proposals may include, without limitation, a rate design including a demand charge or a bifurcation of the S.C. 1 class into heating and non-heating classes or some other rate structure that better reflects customer class homogeneity to bring each group's bills more into line with their respective costs of service." 2012 Rate Order at 188-189. In light of the directive in the 2012 Rate Order to analyze costs imposed on the utilities among low- and high-use consumers, the Companies compared data in its customer information system concerning the use of natural gas for space heating, and equated low-use customers with non-heating customers.

The Companies' updated ECOSS revealed substantial inequities in the current pricing of residential service. PGL and NS Exs. 13.6 provide a useful, one-page summary of the results of the Companies' ECOSS, which reveal substantial subsidies between and among high and low usage gas distribution customers. For PGL, Column C of that exhibit, Line 5, shows total base-rate operating revenues under present rates, after an adjustment for a proposed change in Other Revenues. This line shows that under present rates, residential non-heating customers provide base-rate revenues of $31,960,081. Line 53 shows that the total cost to serve non-heating customers (including PGL's proposed overall rate of return of 7.44% and associated income taxes) is $21,735,396. *This differentiation in cost and revenues reveals that the rates PGL currently charge to residential non-heating customers exceed the cost to serve those customers by more than $10 million per year.* This is equivalent to non-heating customers paying PGL an overall return of 74.16% (line 37), or roughly 10 times the required level of return (7.44%) that PGL claims in this case. AG Ex. 3.0 at 6-7.

For North Shore, again looking at the comparable Exhibit 13.6 from Ms. Hoffman-Malueg's testimony, Column C, Line 5 shows total base-rate operating revenues under present rates, after an adjustment for a proposed change in Other Revenues. This line shows that under present rates residential non-heating customers provide base-rate revenues of $528,013. Line 54 shows that the total cost to serve non-heating customers (including NS's proposed overall rate of return of 7.65% and associated income taxes) is $390,723. *In other words, the rates NS currently charges to residential non-heating customers exceed the cost to serve those customers by more than 35%.* This is equivalent to non-heating customers paying NS an overall return of 70.16% (line 38), or roughly nine times the required level of return (7.65%) that NS claims in this case. AG Ex. 3.0 at 12-13. NS-PGL witness Hoffman-Malueg did not take issue with the Mr. Rubin's calculation of these numbers and return percentages. Tr. at 675.

The Companies' ECOSS clearly demonstrated that the Companies' past advocacy for increasing demand cost recovery through the customer charge created gross inequities in the rates paid by low- and high-usage residential customers. The Companies' proposal to establish separate rates and customer classes for residential heating and non-heating customers in this docket is a recognition of the inequities their quest to eliminate all risk in residential revenue recovery triggered. While the Companies' proposal to bifurcate the heating and non-heating rate classes with a corresponding reduction in the non-heating residential customer charge is an important first step in reflecting cost causation principles in the price paid by residential customers, the Companies' flawed proposal to continue the march toward a 100% Straight Fixed Variable customer charge for heating customers continues the inequities that are rooted in the Companies' hollow assertion that all of its costs are fixed. Even while proposing substantial rate reductions for residential non-heating customers based on the clear results of their ECOSS, the Companies continue to advocate for significant increases to the flat customer charge portion of the residential heating customer bill in order to recover what the Companies claim are its "fixed costs."

Notwithstanding the Companies' alleged embracing of cost-causation principles, there exist clear contradictions in the Companies' alleged objective to follow cost-causation principles and the Companies' focus on increasing the amount of revenue recovered through the flat, monthly customer charge for its residential Heating customers. While Ms. Grace testified that she based her rate design on the ECOSS prepared by PGL/NS witness Hoffman Malueg, the Companies' own ECOSS reveals that the proposed rate design fails to follow basic cost causation principles and acknowledge the very categorization of costs enumerated in Ms. Hoffman Malueg's cost studies. These discrepancies are highlighted in Ms. Grace's claim that virtually 100% of the Companies' residential delivery service costs are "fixed", "i.e. they do not vary with the volume of gas delivered to customers." PGL Ex. 12.0 at 9.

The Companies' ECOSS Reveals Significant Costs Tied to Customer Demand for Natural Gas, And Thus Contradict The Companies' Claim That All Costs Are Fixed.

The Companies' ECOSS, of course, does *not* break costs down into "fixed" costs and "variable" costs, as Ms. Grace's rate design proposals inherently do. Instead, the study divides the functionalized plant and expenses into three broad categories, based on how they are incurred: 1) customer-related, (2) demand (or capacity) related and (3) commodity-related costs. NS Ex. 13.0 at 8. Here is how the Companies' cost of service witness witness Hoffman Malueg defined these three cost categories:

> Customer related costs are incurred to extend service to and attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer related costs are found to vary with the number and density of customers, regardless of the customers' gas consumption (except for, to some extent, bad debt costs in Account 904, which are discussed further below). Examples of costs classified to the customer classification include distribution services, meters, regulators and customer billing and accounting expenses.
>
> Demand related costs are incurred to service the peak demand of the system. Examples of costs classified to the demand classification include transmission and distribution mains, and localized distribution facilities designed to meet customer maximum peak day demand.
>
> Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. However, when, as is the case with North Shore, a gas utility's cost of gas is not recovered through its base rates, very little, if any, of its remaining delivery service cost structure is commodity related.

NS Ex. 13.0 at 8-9. As noted above, the Companies' own cost of service testimony acknowledges the existence of costs that vary by customer usage. Again, Ms. Hoffman Malueg states, "Examples of costs classified to the demand classification include transmission and distribution mains, and localized distribution facilities designed to meet customer maximum peak day demand." *Id.* at 8. Thus, demand-related costs are those that vary with the maximum usage that a customer places on the system. Tr. at 674. Demand-related costs are reflected in the sizing of distribution mains, storage facilities, and other types of distribution facilities. *Id.* Clearly, the largest users of natural gas impose costs on the system that the Companies' lowest users of natural gas do not.

Ms. Hoffman-Malueg also testified:

> Cost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer classes. The most important theoretical principle underlying an ECOSS is that cost incurrence should follow historical embedded cost causation. The costs that customers become responsible to pay

> should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service. By performing an ECOSS in this manner, it can then be used in determining how costs should be recovered from customer classes through rate design.

PGL Ex. 13.0 at 7.

The Commission itself recognized in its last NS-PGL rate order that customer demand for natural gas affects the Companies' costs. In its 2012 Order, the Commission stated:

> The Companies' own data show that they incur substantial costs related to the peak demand that each residential customer places on the system. These demand-related costs are apparent in the sizing of distribution mains, storage facilities, and other types of distribution facilities and related operations and maintenance costs. In addition, the Companies' data show that some residential customers require substantially more expensive meters and regulators than the typical residential customer. In other words, the Companies incur millions of dollars in costs each year that are directly related to the demands residential customers place on the systems. These costs should be allocated to customers in proportion to the amount of natural gas they demand, and it appears that is the methodology employed by the Company in its ECOSSs. However, heating customers place dramatically larger demands on the system than do non-heating customers. *Further, larger heating customers place greater demands on the system than smaller heating customers. Compare, for example, the demand for natural gas from a small apartment to the demand from a large single-family home that may be heating thousands of square feet.*

2012 Rate Order at 178. (emphasis added). This Commission observation makes clear that the Commission's concern about potential cross-subsidies between high and low-users was not limited to the differentiation between Heating and Non-heating customers. The Commission specifically recognized the potential inequities that accompany higher customer charges and non-homogeneous usage characteristics within the residential Heating class.

Unfortunately, after proposing to split the residential class into Heating and Non-heating subclasses, the Companies' rate design proposals stopped short of addressing the clear inequities that exist among Heating customers of varying usage levels. While the Commission's 2012 Order notes that the Companies' ECOSSs correctly allocated costs, the Companies' proposed rate design, which again promotes the fiction that it costs the Companies the same to serve the lowest user of natural gas delivery service as the highest user, does not.

The Companies' own ECOSS establishes that demand-related costs account for 38% of Peoples' and 32% of North Shore's total cost of serving residential heating customers ($147.9 million out of $387.8 million for PGL, $20.7 million out of $65.7 million for NS). NS-PGL Ex. 33.14, p. 1 (PGL); NS-PGL Ex. 33.7 p. 1 (NS). But the Companies have proposed rates that do not recover these residential demand costs from the customers who cause them to be incurred (those customers who use more gas). Instead, the Companies would require low-use residential heating customers to provide substantial subsidies to high-use residential heating customers – charging higher-use heating customers only about 2/3 the demand cost that they impose on the system. *See* AG Ex. 6.03, p. 1 (PGL demand cost is 16.79 cents per therm; PGL proposes a rate of only 10.57 cents per therm) and AG Ex. 6.04, p. 1 (NS demand cost is 9.75 cents per therm; NS proposes a rate of only 6.87 cents per therm), attached as Appendix A.

This is a direct result of PGL's ill-advised advocacy to move toward so-called SFV rates, and the Commission's unfortunate adoption of that position. The very high customer charges that result from SFV rates are wholly unrelated to the cost of service and are grossly unfair to low-use customers. The fundamental flaw in SFV rates is that they treat demand-related costs as "fixed" even though they are incurred based on the amount of gas customers use. It is grossly unfair to spread demand-related costs among all customers irrespective of the amount of gas used by those customers. This effectively requires non-heating customers – who have very low peak-demand requirements compared to heating customers – to pay the same amount toward demand-related costs as a heating customer who might use 10 or 20 times more gas (and who uses most of that gas during the winter peak season). Simply stated, recovering demand-related costs on a per customer, rather than a per therm, basis causes non-heating customers to subsidize the rates of heating customers. In the case of PGL, the customer charge has gotten so high (and includes so much demand-related cost) that the subsidy is enormous. Non-heating customers currently pay rates that are almost 50% more than the cost of service: approximately $32.0 million per year compared to a cost of service of approximately $21.8 million per year. AG Ex. 3.0 at 8.

Of course, the Companies' proposal to bifurcate the Non-heating and Heating costs, and correspondingly reduce the customer charge of Non-heating customers is a significant step in reducing this subsidy. But the Companies' remaining rate design proposals – particularly the proposals to recover 80% of costs through the customer charge for its residential heating and then guarantee 100% recovery of the alleged costs (that include a profit mark-up) through Rider VBA and the conditional SFV tariff contradict the cost-causation principles the Companies claim it endorses, and ignore the Commission's stated interest in ameliorating subsidies within the Heating class. *See* 2012 Rate Order at 178.

The evidence shows that usage of natural gas is not homogenous among residential customers, even with bifurcation of the customer classes. PGL's billing analysis shows that 85% of bills issued to non-heating customers are for 10 therms per month or less. PGL Schedule E-8, page 3. In contrast, one-third of bills issued to heating customers are for 100 therms or more in a month, with about one out of every seven bills showing usage of more than 200 therms in a month. *See* PGL Schedule E-8, page 2; AG Ex. 3.0 at 8.

These differences in consumption levels greatly impact the Companies' demand-related costs. As AG witness Scott Rubin[51] testified, the difference in demand-related costs between heating and non-heating customers is enormous, both because of the difference in the amount of gas consumed and when that gas is consumed. As would be expected, AG Ex. 3.01 shows that heating customers use much more gas during the peak winter heating season than they use during the summer, while non-heating customers' gas usage has a much lower seasonal peak. Indeed, the exhibit shows that the average residential heating customer has a

[51] AG witness Scott Rubin is a regulatory analyst and attorney, specializing in rate design and cost of service analysis, since 1983. Mr. Rubin has testified as an expert before utility commissions or courts in more than a dozen jurisdictions. He also has testified as an expert witness before two committees of the U.S. House of Representatives and one committee of the Pennsylvania House of Representatives. Mr. Rubin has published numerous articles, contributed to books and delivered numerous presentations, on both the national and state level, related to regulatory issues. He also periodically participates as a faculty member in utility-related educational programs for the Institute of Public Utilities at Michigan State University, among other organizations. *See* AG Ex. 3.0 at 1-2.

winter peak month that is 12.4 times the lowest summer month. The corresponding figure for an average non-heating customer is only 3.6 times. Thus, not only do heating customers use much more gas than non-heating customers, they also have dramatically steeper peak demands. AG Ex. 3.0 at 8.

This combination of higher levels of consumption and dramatically higher peak demands results in residential heating customers having much higher demand-related costs per customer than non-heating customers. Specifically, AG Ex. 3.02 shows that average demand-related costs for a heating customer are $17.95 per month. That same exhibit shows that average demand-related costs for a non-heating customer are only $1.19 per month. Thus, the average heating customer causes PGL to incur demand-related costs that are 15 times the average to serve a non-heating customer. But PGL's movement toward SFV rates has used the demonstrably false assumption that each residential customer causes the company to incur the same level of demand-related costs. It is this improper treatment of demand-related costs as being unrelated to consumption that has caused residential non-heating rates to greatly exceed the cost of service, and why the Companies' request to increase the percentage of costs recovered through the customer charge should be rejected. *Id.* at 9.

In sum, the assumption that each customer causes a utility to incur the same level of demand-related costs is the fundamental error in the theory behind SFV rates. SFV rates only bear a rational relationship to the cost of service in the very limited (and comparatively rare) case where you have a relatively homogeneous customer class (that is, each customer has roughly the same level of usage and peak demand). SFV rates – or any rates that recover significant demand-related costs on a per-customer basis – are grossly unfair, and result in significant intra-class cross-subsidies, when a customer class includes large users, small users, seasonal peaking customers, and non-peaking customers. *Id.*

A. Contested Issues – North Shore and Peoples Gas

1. Service Classification No. 1, Small Residential Non-Heating

On the residential rate design front, all parties' proposals, and indeed the Companies' embedded cost of service study ("ECOSS"), point to the fact that PGL and NS residential Non-heating customers are currently paying rates that are significantly higher than the costs they impose on the Companies' delivery systems. The uncontested evidence of record showed that the rates PGL currently charges to residential Non-heating customers exceed the cost to serve those customers by more than $10 million per year. This is equivalent to non-heating customers paying PGL an overall return of 74.16% (line 37), or roughly 10 times the required level of return (7.44%) that PGL claims in this case. AG Ex. 3.0 at 6-7. With regard to North Shore, the rates it currently charges to residential non-heating customers exceed the cost to serve those customers by more than 35%. This is equivalent to non-heating customers paying NS an overall return of 70.16% (line 38), or roughly nine times the required level of return (7.65%) that NS claims in this case. AG Ex. 3.0 at 12-13. This evidence is uncontested. Tr. at 675.

These facts alone prove that the Companies' assertion that all costs are fixed is completely erroneous and contrary to its own cost studies. The Companies' witness, Staff witness Johnson and AG witness Scott Rubin all propose significant reductions in the customer charge for Non-heating residential customers, consistent with the results of the ECOSS, which revealed the significant cross subsidies between Non-Heating and Heating customers, and within the Heating class as a whole. All parties agree that the Residential Non-Heating rates need to be reduced to ensure equity and prevent cross-subsidization. In fact, the differences in the rate design proposals among the Companies, Staff and AG witness Scott Rubin are fairly minor.

As the People noted in the AG Initial Brief, the record evidence shows that the Non-heating class is extremely homogenous. PGL's billing analysis shows that 85% of bills issued to non-heating customers are for 10 therms per month or less. PGL Schedule E-8, page 3. In contrast, one-third of bills issued to heating customers are for 100 therms or more in a month, with about one out of every seven bills showing usage of more than 200 therms in a month. PGL Schedule E-8, page 2; AG Ex. 3.0 at 8. Likewise, for North Shore, the differences are similar, but not identical, to those described in PGL's service area. NS's billing analysis shows that 75% of bills issued to non-heating customers are for 10 therms per month or less. NS Schedule E-8, page 3. In contrast, 39% of bills issued to heating customers are for 100 therms or more in a month; with about one out of every seven bills showing usage of more than 200 therms in a month. NS Schedule E-8, page 2; AG Ex. 3.0 at 13.

Further evidence of the homogeneity of the Non-heating class can be found in AG Ex. 3.02, which revealed that the difference between typical winter and summer usage for the PGL Non-heating class is quite small – differing by fewer than 10 therms per month. AG Ex. 3.0 at 12. Likewise, as explained above and shown on AG Ex. 3.05, the difference between typical winter and summer usage for the NS Non-heating class is quite small – differing by fewer than 15 therms per month. AG Ex. 3.0 at 17.

Initially, the Companies proposed two options for their Non-heating residential charges. One included variable distribution charges, the other did not. Mr. Rubin's proposed residential Non-heating charges follow the second option. He proposes a flat monthly charge for all residential non-heating customers that recovers essentially all base rate costs (that is, all costs except municipal taxes and the commodity cost of gas).[52] PGL's cost-of-service study calculates this cost to be $17.19 per month. PGL Ex. 13.7, p. 3, l. 40.

Specifically, for PGL, he recommends a flat non-heating charge of $15.35 per month. This is a reduction of $6.90 per month from the existing customer charge, and the complete elimination of the per-therm charge (except for Rider SSC), as shown in AG Ex. 6.03 (Appendix A). Specifically, for NS, Mr. Rubin recommends a flat non-heating charge of $16.05 per month. This is a reduction of $5.95 per month from the existing customer charge, and the complete elimination of the per-therm charge (except for Rider SSC), as shown in AG Ex. 6.04 (Appendix B).

As noted above, a flat rate (or SFV rate) would be appropriate only in the relatively rare instance when a customer class is homogeneous. AG witness Rubin testified that the residential non-heating class meets that criterion. Unlike the residential heating class, the PGL non-heating class is quite homogeneous, *with 85% of bills containing usage of 10 therms or less*. PGL Schedule E-8, page 3; AG Ex. 3.0 at 17. The NS non-heating class is likewise quite homogeneous, with 75% of bills containing usage of 10 therms or less. NS Schedule E-8, page 3. Further, as noted above and showed on AG Ex. 3.02, the difference between typical winter and summer usage for the PGL Non-heating class is quite small – differing by fewer than 10 therms per month. AG Ex. 3.0 at 12. Likewise, as explained above and shown on AG Ex. 3.05, the difference between typical winter and summer usage for the

[52] Mr. Rubin's original recommendation for the Companies' Non-heating customers proposed incorporating storage related costs in the flat customer charge. Ms. Grace challenged that proposal in her Rebuttal testimony. Although Mr. Rubin disagreed with Ms. Grace's rationale, he accepted her recalculation of his Non-heating rates to exclude storage-related costs from the flat charge. AG Ex. 6.0 at 1-2. He noted that the amount of storage-related costs charged to non-heating customers is minimal and Mr. Rubin did not consider the treatment of storage-related costs to have a material effect on the rates for non-heating customers. *Id.* at 2.

NS Non-heating class is quite small – differing by fewer than 15 therms per month. AG Ex. 3.0 at 17.

The AG proposals more accurately reflect the homogeneity of the non-heating residential class, provide 100% cost recovery for the PGL and NS non-heating customer class and simplify the Non-heating rate structure. They should be adopted, rather than the Companies' non-heating proposals. To be clear, too, Mr. Rubin agreed in his Rebuttal testimony to the Companies' proposal to recover storage related costs through Rider SSC, rather than through the customer charge. Staff's assertion that his position was something different (Staff IB at 104-105) ignores his Rebuttal compromise on this point. But as noted above, the relative differences among the Companies', Staff's and the AG's Non-heating rate design proposals are minor. Adoption of the Companies' proposed *Non-heating* rates, which recover 80% of *Non-heating* customer costs in the monthly customer charge is not unacceptable to the People. Staff witness Johnson likewise accepted the Companies' Non-heating proposal. Staff IB at 104.

As discussed below, the Commission should focus its attention and analysis on the contested rates for *Heating* residential customers, and the erroneous assumption that all of the Companies' costs are fixed – assumptions that are the foundation for the Companies' flawed rate design proposals.

2. Service Classification No. 1, Small Residential Heating

The requirement in Section 9-201 of the Act that requires the Commission in a contested case to determine whether the rate increases proposed by a utility are "just and reasonable" extends to the design of utility rates. 220 ILCS 5/9-201(c). To make this ultimate determination, the Commission must resolve disputed factual issues, but it must also consider certain equitable and policy considerations. For example, the Commission must ensure that consumers are treated fairly (220 ILCS 5/1-102(d), that "the application of rates is based on public understandability and acceptance of the reasonableness of the rate structure and level" (220 ILCS 5/1-102(d)(ii), and that "the rates for utility services are affordable and therefore preserve the availability of such services to all citizens" (220 ILCS 5/1-102(d)(viii). *Apple Canyon v. Illinois Commerce Comm'n,* 2013 Il.App.3d 100832 (Opinion filed Marcy 5, 2013).

These statutory requirements, coupled with the results of the Companies' ECOSS, clearly establish that demand for natural gas has a substantial effect on cost incurrence, and point to the need for the Commission to revisit its acceptance of the utilities' claim that all of its costs are "fixed" and that the Companies' customer charges – particularly for heating customers – must continually be increased relative to the variable usage charges. PGL's residential Heating class proposals neither recognize nor appropriately recover the substantial demand-related costs that PGL incurs to serve heating customers. Except in the rare case when a customer class is relatively homogeneous, it is improper to recover demand-related costs on a per-customer basis by increasing the flat customer charge. AG Ex. 3.0 at 18.

As noted by Mr. Rubin, the same problem exists within the heating class. There are small customers (homes with just a few hundred square feet) and large customers (homes with several thousand square feet to heat). Data from the U.S. Census Bureau's American Housing Survey for Chicago (AG Ex. 3.07) summarizes data from Table 3.3 of that survey. That exhibit shows that within the City of Chicago, there were approximately 265,000 owner-occupied, single-unit, detached homes. Those houses range in size from fewer than 1,000 square feet (8.5% of homes) to more than 4,000 square feet (6.7% of homes). Moreover, Table 3.5 of the survey shows that 90.6% of all housing units in Chicago heat with natural gas, so it is reasonable to expect these data to fairly represent the diversity within PGL's class of residential heating customers. In addition, of course, PGL also has customers who live in multi-unit buildings with apartments of various sizes, which would serve to further enhance the diversity of the residential heating class. AG Ex. 3.0 at 18-19.

The same lack of homogeneity in usage exists within the heating class in NS's service area. There are small customers (homes with just a few hundred square feet) and large customers (homes with several thousand square feet to heat). Census data with square footage of housing units in Lake County (where most NS customers are located) are not available. Data from other sources, however, indicate that there is considerable diversity within the housing stock in Lake County. AG Ex. 3.09 contains data provided by USA.com. The exhibit shows a mix of housing units in Lake County, ranging from homes with two bedrooms or less (33% of homes) to those with four bedrooms or more (33% of homes); and homes with four rooms or less (22% of homes) to those with nine rooms or more (20% of homes). The same source shows that about 87% of Lake County homes heat with natural gas, so it is reasonable to conclude that this level of diversity applies to the class of NS residential heating customers. AG Ex. 3.0 at 22-23.

The Companies' proposed residential heating rates fail to recognize or appropriately recover demand-related costs. As noted by Mr. Rubin, PGL has proposed a per-therm distribution charge of 13.343¢ per therm for all consumption by residential heating customers. PGL's COSS, however, shows that PGL's demand-related costs are higher than this amount. Specifically, the ECOSS shows that demand-related costs (excluding storage costs, which are recovered through Rider SSC) total $118,353,507, as calculated and shown on AG Ex. 3.08, lines 9-11. When this figure is divided by PGL's projected sales to heating customers, the demand-related cost per therm is 17.078¢ per therm, as shown on line 13 of the exhibit. That is, PGL's demand-related cost is approximately 29% higher than its proposed rate per therm.

NS's proposed residential heating rates, like PGL's, likewise fail to recognize or appropriately recover demand-related costs. NS has proposed a per-therm distribution charge of 7.742¢ per therm for all consumption by residential heating customers. NS's ECOSS, however, shows that NS's demand-related costs are higher than this amount. Specifically, the ECOSS shows that demand-related costs (excluding storage costs, which are recovered through Rider SSC) total $19,610,086, as Mr. Rubin calculates on AG Ex. 3.10, lines 9-11. When this figure is divided by NS's projected sales to heating customers, the demand-related cost per therm is 10.486¢ per therm, as shown on line 13 of the exhibit. That is, NS's demand-related cost is approximately 35% higher than its proposed rate per therm. AG Ex. 3.0 at 23.

In light of these facts, Mr. Rubin recommends customer charge levels that recover less demand-related costs than the 80% level proposed by the Companies. Under Mr. Rubin's proposal, PGL would recover 55% of residential heating customer costs through the customer charge and 60% of NS heating costs. *See* AG Ex. 6.03 (PGL) and 6.04 (NS), page 3[53].

He also recommended that the Companies retain two consumption blocks in its residential heating rate. The first block would recover demand-related costs plus a portion of the customer-related costs that were allocated to the distribution system, primarily through an allocation of distribution mains. Treating some distribution costs as being customer-related is controversial and depends on statistical analyses that can be of questionable validity. But rather than engage in a debate about those analytical procedures in this case, Mr. Rubin

[53] These percentages are calculated by taking the customer charge revenues in the last column divided by total revenues. It doesn't matter (for this calculation) whether you use the companies' revenue requirement column or the AG revenue requirement column - the percentages are the same.

testified that it is reasonable to recover some of that allegedly customer-related distribution cost through the first 50 therms per month that are sold. Recovering these costs in the first consumption block will provide PGL with significant stability in the recovery of those revenues (because heating customers by definition will use the service) and will not distort the demand-related price signal that is sent to customers in the second, more weather-sensitive consumption block. AG Ex. 3.0 at 20.

Mr. Rubin testified that it could be argued that all of the allegedly customer-related portion of distribution costs should be recovered through the first block charge. Doing so, however, would decrease the customer charge by about 50% and approximately double the first block charge. In his opinion, such a result is not consistent with sound rate design principles, including the principles of gradualism and rate continuity, because PGL already has been permitted to greatly increase its customer charge. He recommends, therefore, that 75% of customer-related distribution costs should be recovered through the customer charge, with the remaining 25% of those costs recovered through the first consumption block charge. *Id.* at 20-21.

Mr. Rubin calculated residential rates for both Peoples Gas and North Shore that would implement the AG witness's rebuttal revenue requirement recommendations. AG Ex. 6.03 is a three-page analysis that shows Mr. Rubin's calculation of S.C. 1 rates for PGL. Page 1 of the exhibit shows a comparison of PGL's present rates, PGL's proposed rates (from its rebuttal filing), and his proposed rates. For heating customers, the AG's revenue requirement would be collected if PGL charged a customer charge of $23.99 per month (an increase of $1.74 over the current charge), a first-block charge of 29.148¢ per therm (a decrease of less than one cent per therm), and a second-block charge of 16.793¢ per therm (an increase of less than one cent per therm). The calculation of these rates is shown on pages 2-3 of that exhibit. That exhibit is attached to the AG Initial Brief as Appendix A.

AG Ex. 6.04 contains a similar analysis for North Shore. For heating customers, the AG's revenue requirement would be collected if NS charged a customer charge of $20.51 per month (a reduction of $1.49 per month compared to the current charge), a first-block charge of 17.939¢ per therm (an increase of three-tenths of a cent), and a second-block charge of 9.754¢ per therm (an increase of about four cents per therm). The calculations of these rates are detailed on pages 2-3 of AG Ex. 6.04. That exhibit is attached to the AG Initial Brief as Appendix B.

Mr. Rubin's fair and conservative residential heating rate design proposals should be adopted, rather than the Companies' proposals, which apportion significant demand-related costs on a per-customer basis by increasing the flat monthly customer charge inordinately. Under Mr. Rubin's proposal, PGL would still recover 55% of residential heating customer costs through the customer charge and 60% of NS heating costs, without unjustly punishing the Companies' lower users of heating delivery service. These proposed rates are more equitable than the Companies, and acknowledge the Commission's stated interest in ameliorating subsidies within the Heating class. *See* 2012 Rate Order at 178.

Even if one assumed that the Commission had previously concluded unequivocally that all of the Companies' costs are fixed in a previous order, the concept of public utility regulation requires that the Commission have power to deal freely with each situation that comes before it, regardless of how it may have dealt with a similar or even the same situation in a previous proceeding. *Mississippi Fuel Corp. v. Illinois Commerce Comm'n,* 1 Ill.2d 509, 513 (1953). A record containing new evidence or argument that implicates past decisions compels reconsideration on the new record and may require a different result. See Commonwealth Edison Co. v. Illinois Commerce Comm'n, 405 Ill.App.3d 389,408 (2nd Dist. 2010), citing 220 ILCS 5/10-103 ("any finding, decision or order made by the Commission shall be based exclusively on the record for decision in the case").

The record in this case supports Commission rejection of the assumption that the all of the Companies' costs are fixed. First, as noted above, it is an uncontested fact that the rates PGL currently charges to residential non-heating customers exceed the cost to serve those customers by more than $10 million per year. With regard to North Shore, the rates it currently charges to residential non-heating customers exceed the cost to serve those customers by more than 35%. See AG IB at 103. The point is, the Companies' costs do in fact vary with the volume of natural gas delivered to customers, contrary to NS-PGL witness Grace's assertion that customer natural gas usage does not impact the Companies' costs.

While the Companies note that the notion of increasing the customer charge to recover "fixed" costs dates back to 1995, that Order and the other Commission orders cited in their Initial Brief can be distinguished from the facts in this case. First, back in the 1995 NS/PGL case, the Commission never declared that all costs are fixed. The Commission concluded that the existing customer charge was not fully recovering the Companies' "customer" costs. In that case, the Commission adopted a customer charge rate in the Order that was 50 cents higher than the Companies' proposal of $8.50 – a conclusion based on the testimony of a then Staff witness who is no longer employed by the Commission. Nowhere in that Order did the Commission conclude that all of the Companies' costs were fixed.

The Commission's 2007 PGL/NS rate case order set the customer charge at 50% of the Companies' costs. That position is more in line with Mr. Rubin's proposal to recover 55% and 60%, respectively, of PGL's and NS's residential heating customer costs through the customer charge. In no way does the 2007 Order support an 80% modified straight fixed variable customer charge rate, as proposed by the Companies. The 2009 Rate Order cited by the Companies, while increasing the amount of costs recovered through the customer charge, did not address the issue of cross-subsidization between and among low- and high-usage customers, now being examined by the Commission, as required in the 2012 Rate Order. That Order, too, relied on the Ameren and Nicor decisions, distinguished below, and does not support the radical increase in the customer charge being proposed by the Companies in this docket.

The Companies also note that the Commission allowed the Ameren gas utilities and Nicor Gas to recover, for their residential and small commercial rate classes, 80% of their costs through the customer charge. NS/PGL IB at 157. But a review of those orders shows that those conclusions were based on facts that cannot be applied in this docket. In the Ameren case, no cost study was filed detailing residential costs of service. In fact, the decision to recover 80% of those customers' costs through the fixed customer charge was purely arbitrary. In that instance, the ALJ randomly selected the 80% recovery amount as an alternative to Ameren's request for a full decoupling rider, rather than a specific proposal set at that 80% amount. In approving that amount of recovery of costs through the customer charge, the Commission noted first that Ameren was experiencing declining sales in the residential class, and that less recovery of costs through volumetric charges would help ensure cost recovery. No such evidence of declining residential revenues exists in this docket. In addition, the Commission noted further that the 80% alternative "arguably decreases any disincentive AIU may perceive to implementing gas efficiency programs." That rationale was supplied by the Commission at a time when Ameren's gas efficiency program was voluntary, prior to the General Assembly's enactment of Section 8-104 of the Public Utilities Act, which mandates gas utility-provision of efficiency programs. Thus the notion that any disincentive to the promotion of efficiency programs is required in utility rate design no longer applies.

Finally, in the case of the cited Nicor decision, the Commission specifically noted that the reason the customer charge was being increased to recover 80% of costs through the customer charge was to be consistent with the Ameren decision. In addition, the Commission further noted in that docket:

> The Commission notes, as we did in our prior Ameren decision (Docket No. 07-0585 Cons., at 238), that, on average, the combination of increasing the fixed customer charge and decreasing the volumetric charges for fixed cost recovery is essentially a revenue neutral exercise. Staff apparently believes this rate structure would create an intra-class subsidy within Rate 1, whereby smaller customers would subsidize larger customers within the class. However, as stated in the Gas Distribution Rate Design Manual prepared by NARUC, rate classes should be defined ―according to certain characteristics which are common to all members of the class. These characteristics can include size or load factors. To the extent that the Rate 1 residential class of customers may contain identifiable groups of customers that are not homogenous in their consumption or demand characteristics, the company should provide the Rate 1 customer, billing determinant information and any other statistical information necessary for Staff, the Company and any interested intervenors can to propose changes in the next rate case.

Northern Illinois Gas Company – Proposed Increase in Rates, Order of March 25, 2009 at 90.

As the above quote demonstrates, the Commission had no evidence that intra-class subsidies among residential users existed, and specifically requested an analysis of such subsidies in a next rate case. But no rate case has been filed by Nicor since that 2009 decision. In the instant case, we know that decreasing volumetric charges when customer charges are increased is not a symmetrical, revenue neutral price change. The march toward ever increasing cost recovery in the residential customer charge has significant deleterious impacts on low-usage customers and creates inequitable cross-subsidies between low- and high-usage customers. The evidence in this docket shows that significant increases in customer charges lead to significant cross-subsidies of high users of natural gas by the Companies' lowest users, as noted above and in the AG Initial Brief. We also know that the Residential Heating class is anything but homogenous. See AG IB at 114-115; AG Ex. 3.0 at 18-19, 22-23. Simply put, the facts that drove the Commission to significantly increase the customer charges of Ameren and Nicor ratepayers either no longer apply or are specifically contradicted by the evidence in this docket.

For its part, Staff urges the Commission to reject the Companies' proposed residential Heating rate design, too. Staff notes in its Brief that Staff witness Johnson "disagreed with the Companies' proposal to shift the non-storage related demand costs from the distribution charge to the customer charge for S.C. No. 1 HTG class" just as Mr. Rubin objected to that shift. Staff IB at 106. Mr. Johnson's proposal increases the fixed cost recovery for North Shore to 68%, from its current 67% fixed cost recovery, and increases the fixed cost recovery for Peoples Gas to 61%, from its current 54% fixed cost recovery. While an improvement as compared to the Companies' extreme proposals, Mr. Johnson makes the same mistake of assuming that the Commission must continue the march toward greater cost recovery through the customer charge in his proposals. His proposals also contradict his own stated concern about intra-class subsidies. For example, he also argued that "[t]he Commission should observe what effects the S.C. 1 split has on all of its residential customers before moving forward on significantly greater fixed cost recovery through the customer charge." Staff IB at 106, citing Staff Ex. 8.0 at 25-26, 41.

The People believe that Mr. Johnson's recommendation to not blindly assume that increasing the Companies' customer charge is necessary or appropriate is the right admonition, and one that AG witness Rubin has argued consistently for years. Only AG witness Rubin's proposed rate design uses the Companies' actual demand-related costs and sets residential Heating rates in a way that accurately recovers those costs through the volumetric charges. As noted in the AG Initial Brief, the Companies' proposed residential heating rates fail to recognize or appropriately recover demand-related costs. PGL proposed a per-therm distribution charge of 13.343¢ per therm for all consumption by residential heating customers. PGL's COSS, however, shows that PGL's demand-related costs are higher are approximately 29% higher than its proposed rate per therm. See AG IB at 114-117. NS's proposed residential heating rates, like PGL's, likewise fail to recognize or appropriately recover demand-related costs. NS has proposed a per-therm distribution charge of 7.742¢ per therm for all consumption by residential heating customers. NS's ECOSS, however, shows that NS's demand-related costs are approximately 35% higher than its proposed rate per therm. Id; See AG Ex. 3.0 at 23, AG Ex. 3.08, lines 9-11.

In light of these facts, Mr. Rubin recommends customer charge levels that recover less demand-related costs than the 80% level proposed by the Companies and the 68% (NS) and 61% (PGL) proposed by Mr. Johnson. Under Mr. Rubin's proposal, PGL would recover 55% of residential heating customer costs through the customer charge and 60% of NS heating costs. See AG Ex. 6.03 (PGL) and 6.04 (NS), page 357. Unlike the Companies, he also recommended that the Companies retain two consumption blocks in its residential heating rate. The first block would recover demand-related costs plus a portion of the customer-related costs that were allocated to the distribution system, primarily through an allocation of distribution mains. See AG Ex. 3.0 at 20.

Mr. Rubin's fair and conservative residential heating rate design proposals should be adopted, rather than the Companies' proposals, which apportion significant demand-related costs on a per-customer basis by increasing the flat monthly customer charge inordinately. Under Mr. Rubin's proposal, PGL would still recover 55% of residential heating customer costs through the customer charge and 60% of NS heating costs, without unjustly punishing the Companies' lower users of heating delivery service. As noted in the AG Initial Brief, these proposed rates are more equitable than either the Companies' or Staff's proposals, and acknowledge the Commission's stated interest in ameliorating subsidies within the Heating class. See 2012 Rate Order at 178.

Setting Rates to Recover a Different Revenue Requirement

It is important to note that the Commission is likely to select a revenue requirement that varies from the exact dollar amount any party has proposed. In order to incorporate a new revenue requirement and retain the AG-proposed rate design, the Commission should follow the same procedure as used in AG Exhibits 3.08 and 3.10. Specifically, after the ECOSS is re-run (or rate elements are scaled back in proportion) to reflect adjustments to the Companies' accounting claims, the new results for customer costs, customer-related distribution costs, and demand costs (as well as any sales adjustments) should be used to recalculate AG Exhibits 3.08 and 3.10. This will derive the new customer charge, first block charge, and second block charge for each of the Companies in a manner consistent with the cost of service. *See* AG Ex. 3.0 at 25.

C. Alternative Conditional Straight Fixed Variable Rate Design

In the Utilities' 2011 request for a general increase in delivery service rates, ICC Docket No. 11-0280/11-0281, the Commission approved the Utilities' request for the permanent adoption of Rider VBA. ICC Docket No. 11-0280/0281 – *Peoples Gas, North Shore Gas – Proposed Increase in Rates*, Order of January 10, 2012 Order ("2012 Rate Case Order"). Rider VBA permits the Companies to assess extra surcharges when the actual usage of customers in rate classes 1 and 2 falls below the forecasted usage levels for those classes and credits when usage for those customer groups exceeds forecasted levels. Rider VBA is designed to *guarantee* that the Companies recover the revenue requirement established in the Companies' most last rate case for the residential and small commercial customer classes. This revenue guarantee persists regardless of whether the revenue requirement established in the most recent rate case is actually needed or appropriate going forward, and in spite of the fact that a utility's expenses and revenues are dynamic and ever-changing.

As noted above, the Utilities presented the testimony of Mr. Schott and Ms. Grace, who testified that both North Shore and Peoples Gas were proposing for Commission adoption not only a specific rate design proposal for residential heating and Non-heating customers, but also a conditional SFV tariff that would take effect should the existing Rider VBA terminate due to some third-party action, including an appellate court declaring the tariff unlawful, or action by the Commission. Under this proposal, NS-PGL asks the Commission to approve (1) its proposed rate design for heating and Non-heating customers (which would reflect a decrease in the monthly customer charge for Non-heating customers and an increase in the monthly customer charge for heating customers, and a revised flat per-therm distribution charge that would be the same for both heating and Non-heating customers; *and* (2) a conditional 100% SFV tariff that would take effect if and when Rider VBA is no longer in effect under which the Companies residential heating and non-heating customers would receive customer bills with a rate design that would reflect a fixed monthly customer charge and no volumetric distribution charge. PGL Ex. 12.0 at 10-11.

The Commission Lacks The Authority Under Law To Approve The Utilities' Conditional SFV Tariff, And As Such It Should Be Rejected.

Section 9-201 of the Act establishes the framework under which utilities may propose a change in rates, and the Commission may authorize such changes. That section of the Act provides:

> (a) Unless the Commission otherwise orders, and except as otherwise provided in this Section, no change shall be made by any public utility in any rate or other charge or classification, or in any rule, regulation, practice or contract relating to or affecting any rate or other charge, classification or service, or in any privilege or facility, except after 45 days' notice to the Commission and to the public as herein provided. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules or supplements stating plainly the change or changes to be made in the schedule or schedules then in force, *and the time when the change or changes will go into effect*, and by publication in a newspaper of general circulation or such other notice to persons affected by such change as may be prescribed by rule of the Commission. The Commission, for good cause shown, may

> allow changes without requiring the 45 days' notice herein provided for, by an order specifying the changes so to be made *and the time when they shall take effect* and the manner in which they shall be filed and published.

220 ILCS 5/9-201(a).

The Utilities request that the Commission approve two residential service tariffs, one that would take effect as normally occurs within two days of the end of the 11-month suspension period in this case under Section 9-201(b) of the Act, and a second tariff that would *possibly* take effect at some unknown date in time, depending on events outside of the Utilities and the Commission's control, is contrary to the requirements set forth in Section 9-201(a) of the Act that the published tariff must state "plainly the change or changes to be made in the schedule or schedules then in force, *and the time when the change or changes will go into effect*." 220 ILCS 5/9-201(a). To state the obvious, because neither the Utilities nor the ratepayers who must pay the 100% SFV rates have any idea when the conditional rate change would occur, it is impossible for the NS-PGL tariff to comply with Section 9-201(a)'s mandate that an effective date be provided. The Companies' proposed 90-day and 30-day "notice" language, added in Ms. Grace's surrebuttal testimony, does not remedy this legal flaw. NS-PGL Ex. 48.0 at 10-11. The fact remains, neither the Companies' customers nor the Commission have any idea when such a tariff change would take effect. The tariff is unlawful on its face, and the Companies' request for its approval as a back-up tariff to Rider VBA should be rejected.

In addition, the Companies' conditional SFV tariff is inconsistent with the requirement that changes in rates be set based on a test year. 83 Ill.Admin.Code Part 285. *Professional People for the Public Interest v. Illinois Commerce Commission*, 146 Ill.2d 175, 238, 585 N.E.2d 1032 (*BPI II)* (1991). In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test rule. Section 287.20 of the Commission's rules provides that a utility may, at its option, propose either an historical or a future test year. 83 Ill.Admin.Code Part 287.20. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year. *Business and Professional People for the Public Interest v. Illinois Commerce Comm'n ,* 136 Ill.2d 192, 219, 555 N.E.2d 693 (1989) ("*BPI I").*

The Utilities' conditional SFV tariff by its terms is contrary to the test year rule because it would establish a new rate at an unknown date in the future based on a revenue requirement approved in this case. The conditional SFV tariff is indeed premised on the notion that the revenue requirement set by the Commission in this case will be the appropriate revenue requirement at some unidentified point in the future. For this reason, too, the Companies' conditional SFV tariff should be rejected.

Illinois courts have held that once a rate order is set aside on appeal, the utility cannot continue to benefit from what has been determined to be unlawful portions of a rate increase. *Independent Voters of Illinois v. Illinois Commerce Comm'n,* 117 Ill.2d 90, 104 (1987) ("*IVI")*. The judgment of an appellate court is final upon all questions decided, and if the cause is remanded, the (Commission) can take only such action that conforms to the judgment of the reviewing court. *Id.* at 102. The Companies' 100% SFV rate design proposal, *which is specifically tied to a possible Appellate Court reversal of Rider VBA,* has the effect of subverting the authority of the Illinois Appellate Court by implementing a conditional rate designed to achieve the same goal as a tariff that may be declared unlawful by the Appellate Court. Neither the Commission nor the parties to this docket know how the Second District Appellate Court will rule on Rider VBA or what the Court will say about the notion of guaranteeing the recovery of so-called "fixed costs," the principle upon which Rider VBA is based. But should the appellate court in the pending Rider VBA appeal reverse the Commission's approval of Rider VBA and the mandate is issued by the Appellate Court, the Commission is obliged to respect that decision and any remand instructions that may follow. The Commission's goal in rate setting should not be attempting to predict or circumvent a ruling of the Appellate Court. The Utilities conditional 100% SFV tariff and the proposal to adopt it as a conditional tariff, however, are designed to achieve that goal. For this reason, too, the conditional SFV tariff should be rejected.

Finally, the theory behind public utility regulation is that the Commission should fix rates that "might properly be supposed to result from free competition." *State Public Utilities Comm'n v. Springfield Gas & Electric Co.,* 291 Ill. 209, 218, 125 N.E. 891, 896 (1919). Regardless of how the Utilities frame it, their conditional 100% SFV proposal seeks to ensure recovery of costs regardless of customer usage of the delivery service network, contrary to the Illinois Supreme Court's declaration that utility rates should mirror that which would exist in the competitive marketplace. The Utilitities' view that a revenue requirement must be guaranteed is a radical concept – indeed one that is now being examined by the Appellate Court in the People's Rider VBA appeal -- that should not be set into motion at some unnamed point in time through the consideration and adoption by the Commission of the Utilities conditional SFV tariff. The new 100% SFV rates would conceivably come as quite a shock to customers if, for example, the significantly higher customer charge appeared on a heating customer's bill in the summer months. For this reason, too, the tariff should be rejected.

As noted above, the purpose of Section 9-201 is to provide for reasonable rates: the ICC must "establish the justness and reasonableness of the proposed rates or other charges, classifications, contracts, practices, rules or regulations…" 220 ILCS 5/9-201(c). The Commission has the responsibility of determining proposed utility rate increases, and shall establish rates that it find are just and reasonable. 220 ILCS 5/9-201(c). The Company always retains the option to file a request under Section 9-201 if it feels its current rates are not recovering its costs. Requesting Commission approval of a tariff that seeks to ensure a revenue requirement established in this case into the future notwithstanding an appellate reversal of a certain tariff (Rider VBA) runs contrary to the statutory vehicle established by the General Assembly for utilities to seek rate increases.

For this reason, too, the SFV conditional tariff should be denied.

D. Fixed Cost Recovery and Rider VBA

Rider VBA is a tariff that assures the Companies they will receive the same level of net revenues from customers regardless of how much (or how little) gas the Companies sell. Rider VBA is referred to as a "decoupling" tariff because it decouples the net revenues a utility receives from the amount of utility service it sells. After a four-year pilot initiated in 2008, the Commission approved Rider VBA on a permanent basis in the 2012 PGL-NS Rate Order. The People have appealed that decision, and the case is pending in the Second District Appellate Court. Briefs have been filed and oral argument was held just recently on March 4, 2013. In light of the substantial evidence in this record repudiating the Companies' claim that all of its costs are fixed, and as such the extraordinary means of ensuring cost recovery through Rider VBA is necessary, the Commission should revisit its authorization of Rider VBA. (*See* AG discussion of fixed cost recovery theories above.)

1. Rider VBA is Neither Necessary Nor Equitable.

As noted by AG witness Rubin, the fundamental problem with Rider VBA is that it is based on the assumption that the utility is somehow entitled to recover a certain level of revenues from each customer class in order to recover its fixed costs. This represents a fundamental change in the relationship between a utility and its customers. Utilities have never been guaranteed the recovery of a certain amount of revenue from their customers. Instead, the ratemaking process provides the utility with an *opportunity* to earn a particular return based on a test-year estimate of the amount of services the utility will sell. No utility customer is required to use a certain amount of the utility's service, and a customer is free to use none at all if it so desires. AG Ex. 3.0 at 26.

Mr. Rubin further explained that the nature of utility service is that the utility stands ready, willing, and able to provide service when and if the customer demands it. There are no guarantees. The utility takes the risk that the customer might demand more or less of the service than the utility expects, or that the customer might become so dissatisfied with the cost or quality of utility service that the customer pursues an alternative (such as replacing a gas clothes dryer with an electric one). And the customer assumes the risk that regulators will ensure that the utility will live up to its obligation to provide safe and reliable service at a just and reasonable rate. *Id.*

The gas customer must give the gas utility an easement and allow the utility to install a meter on the customer's property. The customer also must allow the utility to have access to the property at any time to read the meter and test or maintain the facilities. The customer receives a bill from the gas company each month that includes a customer charge for the privilege of being a customer – even if the household used no gas that month. Simply put, the gas customer bears costs and risks that would not be borne in a competitive environment. In return, the gas customer receives a promise of on-demand service direct to the home. That is the fundamental nature of the bargain: A customer cedes certain rights to utilities – rights that the customer does not give to any other supplier or vendor – and agrees to pay a bill each month, even when no service is used. In exchange, the customer receives a promise that service will be delivered when and as needed. The customer does not promise anything else. If a utility's service is bad, or its prices become too high, the customer may install different equipment or appliances to avoid the need for some or all of the utility's service. If the utility's service is good and the prices are reasonable, the customer may go in the opposite direction (for example, by replacing an electric stove with a gas one). *Id.* at 27.

Moreover, the amount that a utility actually sells can depend on many factors. For a natural gas utility, it is affected not only by weather, but also by general economic conditions, the price of alternative fuels, the types of appliances and equipment available in the marketplace, and the quality and reliability of the utility's service. For example, if a utility suffers an interruption in service that lasts two days, it will sell less gas to affected customers. Mr. Rubin testified that it would be grossly unreasonable to allow the utility to increase customers' rates because the utility did not "sell enough gas" during the outage. Simply stated, Rider VBA represents a fundamental change in the relationship between the customer and the utility. Decoupling seeks to have customers collectively guarantee a certain level of sales to the utility – regardless of weather conditions, the community's financial circumstances, global energy concerns, appliance and equipment offerings in the marketplace, or the price and quality of the utility's service. Decoupling shifts an extraordinary level of risk to customers, removes that risk from the utility, and could provide perverse incentives to the utility. *Id.* at 27-28.

Rider VBA provides perverse incentives that are inconsistent with the utility's obligation to serve customers under the Public Utilities Act. As one example, utilities would no longer have an incentive to ensure that it can reliably deliver gas on demand to customers. For example, Mr. Rubin posited, "What would happen to the Companies if they failed to have enough gas in storage or did not properly maintain their systems, causing more outages?" *Id.* at 28. Obviously, the Companies would not sell as much gas as they could have sold. Normally that means that they would earn less money than they could have otherwise. Under decoupling, however, they simply collect less money today, but get to recover those lost earnings from customers tomorrow. So why should a utility with a decoupling rider spend extra money, or incentivize its employees to "go the extra mile" to serve customers, Mr. Rubin asked? Decoupling removes the incentive to maintain a reliable system that is capable of meeting 100% of customers' demands for gas service. *Id.* at 28.

Indeed, taken to its logical conclusion, decoupling could actually encourage the Companies to divert gas to competitive customers (such as power plants) and away from captive customers. They would earn a margin on each sale to competitive customers and would recover (through the decoupling rider) the lost margin on unmade sales to captive customers. Mr. Rubin testified that he could not imagine a worse incentive structure for a natural gas utility. *Id.* at 29.

Other problems are triggered by the existence of Rider VBA. At its heart, decoupling is based on the premise that it is the Commission's job to protect the utility from the vagaries of the marketplace and to safeguard the utility's investors from changes in customer demand. Nothing could be further from the truth. In fact, the fundamental purpose of regulation is to protect consumers from the unfettered market power of monopolists; not to protect the revenue stream or profit levels of those monopolists. *Id.* at 29.

In its Order in Docket No. 11-0280/11-0281, the Commission concluded:

> Some of the problems that Rider VBA was originally intended to protect the utilities from were the reality of fixed costs against a backdrop of a diminishing customer base and resulting revenue losses as well as revenue losses attributable to the implementation of aggressive energy efficiency programs. The reasons to continue Rider VBA are that it is a symmetrical and transparent formula for collecting the approved distribution revenue requirements -- not more or less -- from customers if the Commission chooses not to provide fully for recovery of fixed costs through fixed charges. There are however, additional benefits to ratepayers from Rider VBA. As Staff witness Dr. Brightwell indicated in his testimony, Rider VBA reduces the reliance on forecasting customers and usage to set rates. Staff Exhibit 6.0, pp. 4-5. The forecasts are inevitably incorrect each year, and they are only correct on average. Thus, Rider VBA prevents harm to either the ratepayer or the utility from usage that deviates from the average. It also protects ratepayers in the event the utilities generate or choose a forecast that underestimates sales volumes. *Id.* at 9. Absent Rider VBA, such a forecast set rates too high and unjustifiably increases revenues and profits to the Utilities. *Id.* With Rider VBA, such a forecast is ineffective at increasing profits, because over collections are refunded to customers.
>
> Another advantage of Rider VBA as pointed out by Dr. Brightwell is that it diminishes the advantage that the utility has from choosing the timing of its next rate case. Id. at 5. He

> maintains that without Rider VBA, a forecast that does not account for sales growth leads to over collections. Under this scenario the Utilities have no incentive to petition for a change in rates because such a petition reduces their profits. However, a forecast over-estimating growth in sales causes the Utilities to under collect, and those Utilities have an incentive to file for an increase in rates. Since most rate cases are filed by the Utilities, this asymmetry is to the Utilities advantage and the ratepayer's.

2012 Rate Order at 164.

This rationale no longer applies given the results of the Commission's ECOSS, which show significant demand-related costs. The Commission in its 2012 Rate Order made clear that it was choosing Rider VBA over the Companies' alternative SFV proposal. The Company again offers an SFV rate as a conditional tariff and an alternative to Rider VBA in this docket, should the Illinois Appellate Court reverse the Commission's decision to implement a decoupling rider. In both instances, adoption of Rider VBA (and its alternative) are based on the incorrect assumption that all of the Companies' costs are fixed, and that customer demand does not drive costs. As demonstrated above, the Companies' own cost studies show that such assumptions are false. As Mr. Rubin testified on several occasions, and as the cost studies in this case prove, the very high customer charges that result from SFV rates are wholly unrelated to the cost of service and are grossly unfair to low-use customers. AG Ex. 3.0 . at 30.

The fundamental flaw in SFV rates – and indeed the Commission's adoption of Rider VBA -- is that they treat demand-related costs as "fixed" even though they are incurred based on the amount of gas customers use. It is grossly unfair to spread demand-related costs among all customers irrespective of the amount of gas used by those customers. Simply stated, recovering demand-related costs on a per customer, rather than a per therm, basis causes low-use heating customers (such as those living in small apartments) to subsidize the rates of high-use heating customers (such as those living in large single-family homes). The assumption that each customer causes a utility to incur the same level of demand-related costs is the fundamental error in the theory behind SFV rates and Rider VBA. Like SFV rates – or any rates that recover significant demand-related costs on a per-customer basis – Rider VBA is grossly unfair, and results in significant intra-class cross-subsidies, when a customer class includes large users, small users, seasonal peaking customers, and non-peaking customers. *Id.* at 32-33.

In short, Rider VBA should be removed from the Companies' tariffs and help restore the essential purpose of rate regulation, which is to protect consumers from monopolists' market power.

2. Rider VBA is Unlawful.

As noted above, the People's appeal of the Commission's approval of Rider VBA is pending before the Second District Appellate Court. The People urge the Commission to reconsider its 2012 decision on this point, in light of the clear unlawfulness of this rider.

a. The Commission's Approval of Rider VBA Contradicts Principles of Utility Ratemaking Established by the United States Supreme Court and Adopted by Illinois Courts.

As noted above, Rider VBA adjusts customer rates for PGL and NS residential and small commercial customer classes on a monthly basis to account for the difference between the baseline distribution margin revenue level for the classes established in the last rate case and the actual distribution margin actually experienced each year. In doing so, the Commission contradicts seminal U.S. Supreme Court and Illinois Supreme Court case law that articulates what constitutes just and reasonable public utility rates.

The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. *Citizens Utility Board v. Illinois Commerce Comm'n,* 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995); citing *Camelot Utilities, Inc. v. Illinois Commerce Comm'n*, 51 Ill.App.3d 5, 10, 365 N.E.2d312 (1977).

The U.S. Supreme Court articulated a more specific view of this ratemaking precept in a couple of seminal cases that examined what constitutes a reasonable return within the context of just and reasonable rate setting. All of these cases contradict the view inherent in the Companies' Rider VBA proposal that Peoples and North Shore must be *assured* receipt of its so-called margin revenue level assumed when rates are established in this case.

In the landmark case *Bluefield Waterworks Improvement Co. v. Public ServiceComm'n of West Virginia,* 262 U.S. 279 (1923), the U.S. Supreme Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. In spelling out the factors to be examined by regulators when establishing a utility's rate of return, the high court held that a public utility is entitled to such rates *as will permit it to earn* a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. *Bluefield,* 262 U.S. at 692-693 (emphasis added). The *Bluefield* Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Id.*

The Court specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit *and enable it to raise the money necessary for the proper discharge of its public duties*. *Id.* at 693 (emphasis added).

Investors holding interests in regulated public utilities understand that these companies are dedicated to serving the public and therefore, the investor's possible returns may be limited. *Id.* at 692-693. The Supreme Court elaborated on the principles governing rate of return regulation in the case of *Federal Power Commission v. Hope Natural Gas Company,* 320 U.S. 591, (1941). Here, the Supreme Court reaffirmed its holding in *Federal Power Commission v. Natural Gas Pipeline Co.,* 315 U.S.575, 590 (1942) that "regulation does not insure that the business shall produce net revenues." *Hope Natural Gas,* 320 U.S. at 603. The U.S. Supreme Court specifically rejected the notion that a monopoly must be protected from market realities, such as competition or the effects of price on a consumer's demand and use of the service, in *Market St. Ry. Co. v. Railroad Commission,* 324 U.S. 548, 568 (1945). The Supreme Court explained, "Even monopolies must sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use." *Id. at 568.*

Illinois courts have adopted the *Hope* and *Bluefield* standards and applied them to the regulation of utilities in Illinois: " 'The rate making process under the act, i.e., the fixing of 'just and reasonable' rates[,] involves a balancing of the investor and the consumer interests.' " *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n (1953),* 414 Ill. 275, 287, 111 N.E.2d 329, quoting *Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603, (1944). Similarly, the Illinois Supreme court earlier established that a just and reasonable rate, therefore, is necessarily a question of sound business judgment rather than one of legal formula, and must often be tentative, since exact results cannot be foretold, and that a just and reasonable rate must be less than the value of the service to consumers. *State Pub. Utils. Comm'n v. Springfield Gas & Electric Co. ,* 291 Ill. 209, 216 218 (1919).

The appellate court elaborated on this pronouncement in *Camelot Utilities, Inc. v. Illinois Commerce Comm'n*, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), wherein the Court declared that it is the ratepayers' interest which must come first: "The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail." *Camelot Utilities*, 51 Ill.App.3d at 10; *Citizens Utility Board v. Illinois Commerce Comm'n,* 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

All of these landmark holdings, as well as Illinois courts' interpretations of the decisions, suggest that the Company's request for the guaranteed recovery of its "fixed costs" established when rates are set in this case, as well as a specific revenue stream from the residential and commercial classes (Rates 1 and 2) through Rider VBA, has no support in the utility regulatory law that has guided this Commission's establishment of rates. The Commission's approval of Rider VBA – and thereby adoption of the Companies' mantra that margin revenues must be guaranteed – is tantamount to rejection of the well-established utility ratemaking principles that prescribe what is and is not assured to monopoly utilities under the existing regulatory framework. There simply is no basis in state and federal regulatory law to support the Companies' belief that they are entitled to a guaranteed revenue stream that matches a level established in a rate case.

b. The Commission's Approval of Rider VBA Violates the Act's Prohibition Against Single-Issue Ratemaking.

Illinois law is clear that riders are to be used by the Commission only in very specific and exceptional circumstances, as this Court highlighted in its 2010 decision in the case of *Commonwealth Edison v. Illinois Commerce Commission*, 405 Ill.App.3d 389, 411(2d Dist. 2010) After reviewing and laying out in the opinion all pertinent case law addressing riders, this Court established a clear, two-part test which defined the very limited framework for permissible riders. First, the *ComEd* decision stated that riders are to be used only when they are designed to "recover a particular *cost* if (1) the *cost* is imposed upon the utility by an external circumstance over which the utility has no control and (2) the *cost* does not affect the utility's revenue requirement." *Id.* at 687 (emphasis added). The Court further explained that:

> a rider is appropriate only if the utility cannot influence the expense (*Citizens Utility Board,* 166 Ill.2d at 138 ['a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, or fluctuating expenses') and the expense is a pass-through item that does not change *other expenses or increase income* (*Citizens Utility Board,* 166 Ill.2d at 138 (*a valid rider has no 'direct impact on the utility's rate of return*').

Id. at 687 (emphasis added).

Rider VBA by its very nature fails both prongs of that test. First, the isolation and guaranteed recovery of forecasted revenues, which is what Rider VBA does, is not recovery of a pass-through "expense" or "cost" of any kind. There's no particular expense or cost being recovered. Rider VBA fails the second prong of the test laid out by the Court because the sole purpose of Rider VBA is to guarantee an established revenue stream and change its net income. By its very definition, Rider VBA increases income when revenues from residential and small commercial customer classes are down, and decreases income when revenues are up, thereby directly impacting the utility's rate of return. The Commission has repeatedly observed that Rider VBA in fact does affect the companies' rate of return because in each of the annual reconciliation proceedings that have taken place to date, the Commission orders recorded the differing ROEs, both with and without Rider VBA. *See,* e.g., *See* ICC Docket No. 10-0237,10-0238 (cons.), Order of March 9, 2011 at 3, 6; ICC Docket No. 09-0123 (North Shore), Order of February 10, 2010 at 12; ICC Docket No. 09-0124 (PGL), Order of February 10, 2010 at 12. These Rider VBA reconciliation dockets each specifically cite movement in the ROE as a result of the Rider VBA adjustments. For this reason, too, Rider VBA should be terminated.

c. Rider VBA Violates the Act's Prohibition Against Retroactive Ratemaking.

Rider VBA should also be terminated because it violates the Act's prohibition against retroactive ratemaking by permitting annual rate adjustments after rates are established in this case. Rider VBA conflicts with traditional prospective ratemaking and the rule against retroactive ratemaking because it illegally locks in an artificial level of revenues per customer – a benchmark never before recognized in utility ratemaking – through a formula that triggers annual rate adjustments for residential and small business customers after rates have been established in a rate case order. These adjustments are made to guarantee what the Commission now believes is a utility entitlement, the artificial benchmark of a set *revenue* level per customer class, rather than the recovery of certain *expenses* that qualify for rider treatment, such as purchased gas, environmental remediation expenses and legally mandated fees.

Second, Rider VBA absolutely suggests that the rates (charged under the order establishing the revenue requirement) are in some way excessive or insufficient. The Order unequivocally provides that if revenues from residential and small business customers do not meet the benchmark revenue level established for each class each year, then they are either excessive, thereby requiring a Rider VBA reduction, or insufficient, thereby requiring a Rider VBA surcharge. The shortfall or excess tabulated in the Rider VBA true-up is collected over a nine-month period beginning each April.

This seesawing of monthly surcharges (or credits) triggered by Rider VBA is the kind of retroactive adjustment of rates that Illinois courts held were illegal. Section 9-201 of the Public Utilities Act ensures that rates for utility service are set prospectively. 220 ILCS 5/ 9-201. The Illinois Supreme Court has held repeatedly that the Public Utilities Act does not permit retroactive ratemaking; that is once the Commission establishes rates, the Act does not permit refunds if the established rates are too high, or surcharges if the rates are too low. *BPI I*, 136 Ill.2d at 209; *Citizens Utilities Co. v. Illinois Commerce Comm'n,* 124 Ill. 2d 195, 207; 529 N.E.2d 510 (1988). Rider VBA violates the prohibition against retroactive ratemaking by permitting annual rate adjustments after rates are established in this case that are not contemplated by the Act.

Given both the absence of both specific statutory authority authorizing the retroactive adjustment of customer rates on an annual basis to ensure a benchmark revenue level for two customer classes, it is clear the Commission lacks the authority to approve Rider VBA.

d. Rider VBA Violates the Commission's Test Year Rules.

Rider VBA likewise violates the Commission's test year rules. The process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common point in time referred to as a test period or test year. *See Business & Professional People for the Public Interest v. Illinois Commerce Commission,* 146 Ill.2d 175, 238, 585 N.E.2d 1032 (*BPI II)* (1991). In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test rule. *See* 83 Ill.Admin.Code Part 285. Section 287.20 of the Commission's rules provides that a utility may, at its option, propose either an historical or a future test year. 83 Ill.Admin.Code Part 287.20. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year. *BPI I,* 136 Ill.2d at 219.

Adjusting customer rates while ignoring all other elements in the ratemaking formula to reflect a single component of the revenue requirement established in a rate case – a designated revenue benchmark level for Rates 1 and 2 -- constitutes a violation of the test year rules. The calculation of Peoples' and North Shore's revenues for purposes of setting rates is subject to test-year principles. Rider VBA violates the Commission's and Illinois law's test-year principles by selecting only one component of the revenue requirement, in this case a slice of overall revenues (margin revenues per customer in the Rate 1 and 2 classes), tracking changes in that revenue requirement component and then assessing rate adjustments to recognize this change. Such an approach distorts test year matching by continuously revising utility prices for changes in future usage per customer, even though other elements of the test year revenue requirement calculation are not being systematically updated. For this reason, too, Rider VBA should be terminated.

e. Illinois Law is Clear that "Lost Revenues" Cannot be Recovered Through A Rider.

The Illinois Appellate Court in the *Finkl & Sons v. Illinois Commerce Comm'n,* 250 Ill.App.3d 317 (1st Dist. 1993), specifically reversed the Commission's approval of a rider that f required ratepayers to reimburse a utility for revenues lost due to energy efficiency and conservation measures. In *Finkl*, the rider at issue, like Rider VBA, also would have authorized Commonwealth Edison Company to charge ratepayers for lost revenues associated with demand-side management activities, similar to the Companies' request in this docket to adjust rates each month when margin revenues fall below a revenue per customer baseline established in this Order. The *Finkl* Court noted that rider recovery of lost revenues associated with the DSM programs "fails to take into consideration Edison's aggregate costs and revenues, which is also the vice inherent in this revenue recapture…" *Finkl*, 250 Ill.App.3d at 328. The Court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or DSM programs:

> "Requiring ratepayers to bear the expense of services they avoid due to conservation or DSM programs is not only incredible, but runs afoul of basic ratemaking principles. The Act requires that rates be set which 'accurately reflect the long-term cost of such services and which are equitable to all citizens.' (Ill.Rev.Stat.1989, ch. 111 2/3, par. 1-102 (now 220 ILCS 5/102 (West 1992))(section 1-102).) Both in *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n* (1973), 55 Ill.2d 461, 483, 303 N.E.2d 364, and in C*andlewick Lake Utilities*

> *Co. v. Illinois Commerce Comm'n* (1983), 122 Ill.App.3d 219, 227, 460 N.E.2d 1190, the courts have asserted that ratepayers are not to pay certain costs unless they directly benefit from them. The lost revenue charge here does not reflect the cost of providing electric service, does not reflect a cost that benefits ratepayers and, further, adds to Edison's revenues without regard to whether Edison's demand or revenues increased because of factors unrelated to DSM programs. This is yet another basis for reversal.

Id. at 329.

The notion of reimbursing Peoples Gas and North Shore for declining revenues associated with, among other phenomena, energy efficiency and conservation, is at the heart of the Companies' decoupling proposal. Approval of Rider VBA violates the Act's requirement that rates be set which "accurately reflect the long-term cost of such services and which are equitable to all citizens." 220 ILCS 5/102. Ratepayers are not to pay certain costs unless they directly benefit from them. *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n* (1973), 55 Ill.2d 461, 483, 303 N.E.2d 364, and in *Candlewick Lake Utilities Co. v. Illinois Commerce Comm'n* (1983), 122 Ill.App.3d 219, 227, 460 N.E.2d 1190. The Commission had no authority to require ratepayers to pay for gas delivery service they are not using, since they derive no benefit from service they do not use. Given the clear direction provide by the *Finkl* Court in its specific rejection of ratepayers compensating a utility for lost revenues arising from energy efficiency and other measures, as well as the Act's requirement that ratepayers shall only pay for utility costs that directly benefit from them, the Commission's decision to approve Rider VBA should be terminated.

For all of the reasons discussed above, the Commission should terminate Rider VBA.

X. TRANSPORTATION ISSUES

A. Uncontested Issues

1. Purchase of Receivables (Withdrawn)

2. Commission Authority to Order Investigation on Provider of Last Resort

B. Contested Issues

1. Cost Allocation Between Sales Customers and Small Volume Transportation Customers

2. Recovery of Supply-related Costs from Small Volume Transportation Program (Choices for You^{SM} or "CFY") Customers

3. Recovery of Small Volume Transportation Program (Choices for You^{SM} or "CFY") Administrative Costs

4. Provider of Last Resort Investigation

XI. CONCLUSION

For the foregoing reasons, the People request that the Commission enter an order establishing just and reasonable rates for the North Shore Gas Company and Peoples Gas Light & Coke Company incorporating the adjustments proposed herein, and employing the rate design discussed above.

Respectfully submitted,

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